

1 STATE OF MICHIGAN  
 2 BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

3 In the matter of the application of  
 4 Wisconsin Electric Power Company  
 5 d/b/a We Energies for approval of a Case No. U-14707  
 6 power supply cost recovery plan and  
 7 authorization of monthly power supply Volume 3  
 8 cost factors for the calendar year 2006  
 9 \_\_\_\_\_/

7 CROSS-EXAMINATION

8 Proceedings held in the above-entitled matter  
 9 before Daniel E. Nickerson, Jr., J.D., Administrative  
 10 Law Judge, at the Michigan Public Service Commission,  
 6545 Mercantile Way, Room C, Lansing, Michigan, on  
 11 Wednesday, April 26, 2006, at 9:24 a.m.

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25 REPORTED BY: Erin Stilman (CSR-3588)

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1 Wednesday, April 26, 2006

2 At 9:24 a.m.

3 - - -

4 (Exhibits LP-1 through LP-24 marked.)

5 (Exhibits A-1 through A-12, A-16 and A-17  
6 marked.)

7 JUDGE NICKERSON: All right. On the  
8 record. Good morning everyone. This is the date and  
9 time set for the hearing before Michigan Public Service  
10 Commission in Docket No. U-14707.

11 My name is Daniel Nickerson. I'm an  
12 Administrative Law Judge with SOAHR assigned on this  
13 case. Let's take appearances of counsel for the record  
14 beginning with the applicant, please.

15 MR. BLOOMBERG: Good morning, your  
16 Honor. Ronald William Bloomberg with the law firm of  
17 Miller, Canfield, Paddock & Stone appearing on behalf  
18 of applicant, Wisconsin Electric Power Company. And I  
19 have Harvey J. Messing with me as well.

20 JUDGE NICKERSON: Thank you, sir.

21 MR. WATERS: Thomas J. Waters of the law  
22 firm of Fraser, Trebilcock, Davis & Dunlap on behalf of  
23 intervenor Tilden Mining Company, L.C. and Louisiana  
24 Pacific Corporation. With me also appearing on behalf  
25 of those two entities is Mr. David S. Marvin and Robert

1 Nelson.

2 MR. ODUNLAMI. Good morning, your Honor.  
3 Emmanuel Odunlami, assistant attorney on behalf of  
4 Staff.

5 JUDGE NICKERSON: All right. Thank you  
6 for your appearances.

7 Mr. Bloomberg, you may proceed,  
8 sir.

9 MR. BLOOMBERG: Thank you, your Honor.  
10 I'd like to start out by indicating that the parties  
11 have reached a stipulation to the admission of various  
12 discovery responses, and we have presented those to the  
13 court reporter. They have been marked by the court  
14 reporter as proposed Exhibits LP-1 through LP-24, and  
15 also as proposed Exhibits A-16 and A-17, and pursuant  
16 to that stipulation I would move for the admission of  
17 those documents as exhibits.

18 JUDGE NICKERSON: All right. Thank you,  
19 Mr. Bloomberg.

20 Is Mr. Bloomberg's statement in  
21 agreement?

22 MR. WATERS: Mr. Bloomberg has correctly  
23 stated the matters with regard to those exhibits.

24 MR. ODUNLAMI: No objection, your Honor.

25 JUDGE NICKERSON: Very well. Proposed

1 Exhibits LP-1 through LP-24 are admitted, as well as  
2 Exhibit A-20 -- 16 and A-17.

3 MR. BLOOMBERG: Thank you, your Honor.  
4 At this time the Company would like to call Thomas  
5 Lorden to the stand.

6 - - -

7 T H O M A S L O R D E N

8 was called as a witness on behalf of Wisconsin Electric  
9 Power Company and, having been duly sworn to testify  
10 the truth, was examined and testified as follows:

11 DIRECT EXAMINATION

12 BY MR. BLOOMBERG:

13 Q. Good morning. Could you please state your name for the  
14 record.

15 A. Thomas P. Lorden.

16 Q. And by whom are you employed?

17 A. Wisconsin Electric Power Company.

18 Q. Did you cause to be prepared in this matter a document  
19 entitled, "The Direct Testimony Of Thomas P. Lorden On  
20 Behalf Of Wisconsin Electric Power Company," consisting  
21 of a cover page and 47 numbered pages?

22 A. Yes, I did.

23 Q. Did you also cause to be filed in this matter a  
24 document entitled, "The Rebuttal Testimony Of  
25 Thomas P. Lorden On Behalf Of Wisconsin Electric Power

1 Company," consisting of a cover page and two pages?

2 A. Yes, I did.

3 Q. Do you have those documents in front of you?

4 A. Yes, I do.

5 Q. Do you have any revisions or corrections to those  
6 documents?

7 A. Yes, I have corrections to my direct testimony.

8 First correction is on page 36.

9 JUDGE NICKERSON: Excuse me. Off the  
10 record.

11 (Discussion off the record.)

12 JUDGE NICKERSON: Back on the record.

13 Thank you, Mr. Bloomberg.

14 Q. (Continuing): Could you state the first correction for  
15 me.

16 A. Yes, the first correction on page 36, line 8; the first  
17 number there 2005 should be 2004.

18 Q. Okay. And do you have another correction?

19 A. Yes, I have correction on page 45, line 28, and the  
20 amount under column PSCR Cost should be .00317.

21 Q. On line 27 or line 28?

22 A. Line 28.

23 Q. And the description on that line is?

24 A. Fuel.

25 Q. Thank you.

1 A. And the final correction is on page 46, line 1,  
2 Purchased Power, the amount there should be a  
3 positive .00070.

4 Q. Okay. Were these last two corrections you just  
5 described a result of a change in the input items  
6 underlying these numbers or in the calculation of these  
7 numbers?

8 A. No, just a correction of the calculation.

9 Q. Do you have before you what's been marked by the court  
10 reporter as proposed Exhibits A through A-15?

11 Excuse me, your Honor.

12 A. A-1 through 12?

13 Q. I'm sorry, A-1 through A-12?

14 A. Yes, I do.

15 Q. Were those prepared by you or under your direction?

16 A. Yes, they were.

17 Q. Do you have any, do those, do you have any revisions to  
18 those?

19 A. Yes, I do. The first revision is to Exhibit A-1,  
20 TPL-1, page 1 of 4.

21 Q. Is that revised page included in the documents before  
22 you?

23 A. Yes, it is.

24 Q. Were there any other revisions to your pre-filed  
25 exhibits?

1 A. Yes, there are corrections to A-2, Exhibit A-2, TPL-2,  
2 page 1 and page 2.

3 Q. And are those revisions incorporated in the pages  
4 marked by the court reporter?

5 A. Yes.

6 Q. If I were to ask you today the questions that were  
7 included in your pre-filed direct and rebuttal  
8 testimony would your answers today be the same as  
9 included in there?

10 A. Yes, they would.

11 Q. Are those true and correct, to the best of your  
12 knowledge?

13 A. Yes, they are.

14 MR. BLOOMBERG: Your Honor, I move for  
15 the binding in of the pre-filed Direct and Rebuttal  
16 Testimony of Thomas P. Lorden and move for the  
17 admission of proposed Exhibits A-1 through A-12, and  
18 tender the witness for cross-examination.

19 JUDGE NICKERSON: Okay. Well, any  
20 objection to binding in the Direct Testimony?

21 MR. WATERS: No, your Honor.

22 MR. ODUNLAMI: No, your Honor.

23 JUDGE NICKERSON: It may be bound into  
24 the record.

25

S T A T E   O F   M I C H I G A N  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

|                                               |   |                  |
|-----------------------------------------------|---|------------------|
| In the matter of the application of           | ) |                  |
| WISCONSIN ELECTRIC POWER COMPANY              | ) |                  |
| d/b/a We Energies for approval of a power     | ) |                  |
| supply cost recovery plan and authorization   | ) | Case No. U-14707 |
| of monthly power supply cost recovery factors | ) |                  |
| <u>for the calendar year 2006</u>             | ) |                  |

DIRECT TESTIMONY OF THOMAS P. LORDEN

ON BEHALF OF

WISCONSIN ELECTRIC POWER COMPANY

September, 2005

## WISCONSIN ELECTRIC POWER COMPANY

Before the Michigan Public Service Commission

Direct Testimony of Thomas P. Lorden

1 Q. Please state your name and business address.

2 A. Thomas P. Lorden, 231 West Michigan Street, Milwaukee,  
3 Wisconsin 53203.

4 Q. What is your present employment?

5 A. I am employed by Wisconsin Electric Power Company, d/b/a We  
6 Energies ("Wisconsin Electric" or "Company") as a Senior  
7 Project Specialist in the Regulatory Affairs and Policy  
8 Department. In this position, I am responsible for fuel  
9 filing and reporting to the various regulatory agencies.

10 Q. Please describe your qualifications and background.

11 A. I earned a Bachelor of Arts Degree in Business Administration  
12 from the Marquette University with a specialization in finance  
13 in 1980.

14 I joined Wisconsin Electric in 1968. From 1968 to 1975, I  
15 worked in the Plant Accounting Division. From 1975 until  
16 1980, I held various positions in the Load Research area of  
17 the Corporate Planning Department.

18 From 1980 to 1998, I was in the Rates Section. While in  
19 the Rates Section, I was involved in the development of  
20 numerous cost-of-service studies to support the Company's rate

1 and regulatory needs. In my previous position, as Team Leader  
2 for Fossil Fuel, Nuclear and Purchase Power Accounting, I was  
3 responsible for fuel accounting and reporting. I have  
4 previously testified before the Michigan Public Service  
5 Commission ("MPSC" or "Commission") on cost-of-service in Case  
6 Nos.U-7592, U-10000 and U-10183. I have also provided  
7 testimony for the 2005 Power Supply cost Recovery ("PSCR")  
8 plan in Case No. U-14264, 2004 PSCR reconciliation in Case No.  
9 U-13907-R, 2004 PSCR plan in Case No. U-13907, 2003 PSCR plan  
10 in Case No.U-13556, 2003 PSCR reconciliation in Case No.U-  
11 13556-R, 2002 PSCR plan in Case No.U-13107, 2002 PSCR  
12 reconciliation in Case No.U-13107-R, 2001 PSCR plan in Case  
13 No.U-12615, 2001 PSCR reconciliation in Case No.U-12615-R, the  
14 1995 PSCR plan in Case No.U-10707 and the 1994 PSCR  
15 reconciliation Case No.U-10428-R.

16 Q. What is the purpose of your testimony in this proceeding?

17 A. The purpose of my testimony is to develop the power supply  
18 cost recovery factors for the period covered by the Company's  
19 2006 power supply cost recovery plan. To do this, I developed  
20 the average power supply costs using the projected costs for  
21 January through December, 2006. The factors were calculated  
22 using the base power supply costs from the generation and  
23 purchased power requirements and costs as ordered by the  
24 Commission in its Opinion and Order issued in Case No. U-  
25 12725, on September 16, 2002. In addition, my testimony  
26 describes the procurement of fossil fuel, nuclear fuel and  
27 related fuel cycle services and the components involved in the  
28 calculation of nuclear fuel expense.

1 Q. Are you sponsoring any exhibits in this proceeding?

2 A. Yes, I am sponsoring Exhibits A-1 (TPL-1) through A-12 (TPL-  
3 12). These exhibits relate to the Company's forecast of  
4 electric sales, procurement of fossil fuels, projected fuel  
5 costs, the operation of the Company's generating units and the  
6 estimates of purchased power and energy interchange for the  
7 year 2006 and for the forecast period of 2007 through 2010.

8 Q. Were these exhibits prepared by you or under your direction and  
9 supervision?

10 A. Yes.

11 OVERVIEW

12 Q. Could you provide an overview of the process by which fuel and  
13 purchase power expenses are projected?

14 A. Yes. The process can be divided into three distinct steps.

15 Q. Please describe the first step.

16 A. The process begins by forecasting the electrical energy and  
17 demand requirements of Wisconsin Electric customers. This  
18 work is performed by the Forecasting and Load Research Team of  
19 the Regulatory Affairs and Policy Department using econometric  
20 modeling and time trending.

21 Q. Please describe the second step.

22 A. The second step is to project the operation of the generating  
23 system needed to meet the forecasted energy and demand  
24 requirements. This work is performed by the Commodity  
25 Resources Department ("Commodity Resources") of the Commodity  
26 Business Unit using a production cost model. Both the  
27 quantities of fossil fuel burned and the amounts of power  
28 purchased and energy interchanged are projected in this step.

1 Q. Please describe the third step.

2 A. The third step is to project the delivered cost of fossil  
3 fuels required by the above fuel consumption projection. This  
4 work is performed by Commodity Resources. Due to the  
5 relationships between quantity of fuel delivered and the price  
6 of fuel delivered, there may be several iterations performed  
7 between steps two and three. Nuclear fuel costs will be  
8 discussed later in my testimony.

9 SALES FORECASTS

10 Q. Please discuss each of these three general steps in more  
11 detail, beginning with the forecast of energy and demand  
12 requirements for the period 2006 through 2010.

13 A. The process of forecasting demand and energy employs  
14 econometric modeling and time trending. Billed (or billing  
15 month) energy is the final product of the sector (residential,  
16 farm, commercial, industrial, public authority, and municipal)  
17 energy forecasts. Based on recent historical relationships,  
18 the billed sector forecasts are broken down by rate class and  
19 rate schedule, as well as state jurisdiction for the  
20 commercial and industrial sectors. The billed forecasts are  
21 subsequently converted to booked (or calendar month) energy  
22 forecasts by estimating amounts of unbilled (consumed in the  
23 current calendar month but a different billing month) energy.  
24 By applying loss factors to the booked forecasts and adding  
25 expected company use and wholesale contract sales, the  
26 forecast of total energy requirements is obtained.

27 The Residential and Farm rate class energy forecasts are  
28 developed using a trended projection of usage per customer,

1 combined with separate forecasts of the number of customers.  
2 In addition to weather, the main drivers for residential class  
3 usage per customer are time, weather sensitive appliance  
4 saturation, expected lighting hours, and a variable for  
5 holiday lighting. The farm class forecast for usage per  
6 customer is essentially time trended. Forecasts of customers  
7 in the residential and farm sectors are based on county-level  
8 forecasts of households and population and are benchmarked to  
9 historical billed data. Adjustments are made to the basic  
10 billing month customer forecast to represent variability in  
11 the number of billing cycles per billing month.

12 Commercial and Industrial Sector forecasts are developed  
13 for segments determined by groupings of SIC codes. Electricity  
14 consumption for the segments in the Commercial sector is  
15 assumed to be a function of weather, employment, and billing  
16 cycles per billing month. Electricity consumption in the  
17 Industrial sector is modeled as a function of national  
18 industrial output. Explicit forecasts are developed for a  
19 small number of the largest customers in the General Primary  
20 class. The Commercial and Industrial forecasts combine to  
21 produce the forecasts for the General Secondary and General  
22 Primary rate classes.

23 Energy usage in the Public Authority rate class, which is  
24 comprised primarily of street lighting usage, varies little  
25 from year to year. That forecast is based upon actual usage  
26 in calendar year 2003. The forecast of company use is based  
27 upon actual billed data for the twelve month period ending  
28 June, 2002. Energy consumption by Municipal wholesale

1 customers is modeled individually by examining trends in sales  
2 and changes to customer contracts.

3 Native system peak demand, excluding the usage by the  
4 Empire and Tilden mines and load management impacts, is the  
5 dependent variable in the peak demand forecast process. The  
6 driving variables for the peak forecast are monthly native  
7 system (excluding mines) energy, cooling and heating variables  
8 based upon appliance ownership and weather, and variables to  
9 specify the season and to account for past impacts of public  
10 appeals for load reduction and recessions. Adding specific  
11 quantities for the firm and curtailable mine loads and  
12 subtracting all load management impacts yields the forecast  
13 for the net native system peak demand. Finally, specific  
14 demand forecasts for wholesale contract sales are added to  
15 yield the net demand obligation forecast.

16 Q. When were the forecasts for 2006-2010 developed?

17 A. The forecasts were developed in September of 2004.

18 Q. Are you sponsoring any exhibits relating to the sales forecast  
19 portion of your testimony?

20 A. Yes. I am sponsoring Exhibits A-1(TPL-1) and A-2(TPL-2) which  
21 were prepared under my direction.

22 Q. What does Exhibit A-1 (TPL-1) show?

23 A. The System's Energy and Peak Demand forecasts for 2006-2010  
24 along with the Development of the Total Peak Month Demand  
25 Obligation are presented in Exhibit A-1 (TPL-1).

26 Q. Have you included a forecast for electricity requirements for  
27 2006-2010 in the Company's Michigan service territory?

MPSC

- 7 -

Thomas P. Lorden

1 A. Yes. The Michigan service territory's sales are presented in  
2 Exhibit A-2 (TPL-2). This exhibit is based upon the Company  
3 forecast methodologies discussed previously.

4 Q. In the monthly version of Exhibit A-2 (TPL-2), some months the  
5 amounts for Losses and Net Accrual are negative numbers. Can  
6 you explain this?

7 A. Yes. Losses obviously are a positive number, being the  
8 difference between generation level energy and customer level  
9 energy. The Company estimates its losses in Michigan to be  
10 approximately 7,000 MWH per month. The net accrual from one  
11 month to the next is the difference between that month's  
12 billed sales and its booked sales. The Empire and Tilden  
13 mines, the bulk of Wisconsin Electric's sales in Michigan, are  
14 billed on a one-month lagged basis, meaning this month's  
15 booked sales are billed next month, and this month's billed  
16 sales were booked last month. When usage from one month to  
17 the next changes significantly, even if only because of the  
18 number of days in the month, this results in a large  
19 difference between the month's booked and billed values, or  
20 net accrued. The number is positive when usage increases over  
21 the previous month; the booked value is greater than the  
22 billed value. The number is negative when usage decreases  
23 from one month to the next; the booked value is less than the  
24 billed value. Since Empire and Tilden are so large relative  
25 to the rest of Wisconsin Electric's sales in Michigan, their  
26 net accrual can be such a large negative number that it can  
27 actually exceed the losses in the month. When that happens,  
28 the Losses and Net Accrued total is a negative value.

MPSC

- 8 -

Thomas P. Lorden

1 Q. Do you consider these forecasts to be reasonable?

2 A. Yes.

3 OPERATION OF GENERATING SYSTEM

4 Q. You previously stated that the second general step in the  
5 process of projecting fuel costs is to project the operation of  
6 the generating system needed to meet the forecasted energy and  
7 demand requirements. Could you describe this step in more  
8 detail?

9 A. Commodity Resources staff reviews the projected system demand  
10 and energy and evaluates the adequacy of the Company's  
11 generation resources. Based on these projections and  
12 evaluations, alternatives are defined and plans are developed  
13 for meeting projected loads. Factors that are incorporated in  
14 the projection include: (1) generating unit operating  
15 characteristics, fuel costs, planned outage schedules, (2) firm  
16 transmission availability and (3) projections of energy costs  
17 from Midwest Independent Transmission System Operator ("MISO").  
18 Commodity Resources staff then establishes the most economic  
19 energy mix of system generation and purchased power to  
20 adequately meet load projections consistent with reasonable  
21 levels of system reliability. In addition, the Company operates  
22 a steam utility system in downtown Milwaukee. Steam is  
23 supplied to the system from the Valley Power Plant. Fuel costs  
24 applicable to the steam utility are calculated on a cost per  
25 million Btu basis. The allocation of the costs from the  
26 electric utility to the steam utility is provided as the Steam  
27 Transfer Credit. Similarly, the Company operates a steam and  
28 chilled water system at the Milwaukee County Grounds. This is

1 a steam utility power plant, which also produces electric power  
2 for our system. Fuel costs applicable to the electric utility  
3 are calculated on a cost per million Btu basis. The allocation  
4 of the costs from the steam utility to the electric utility is  
5 provided as the Electric Transfer Debit.

6 Q. Describe the criteria for determining the hour-by-hour adequacy  
7 of generating resources.

8 A. Currently, Wisconsin Electric is a member of the Mid-America  
9 Interconnected Network ("MAIN"), a regional reliability council  
10 which encompasses utilities in the Upper Peninsula of Michigan,  
11 Wisconsin, Illinois, and Missouri. MAIN has operating reserve  
12 requirements which the Company deems as appropriate and  
13 necessary, and to which it subscribes. MAIN Operating Guides  
14 require that the system be operated so that various  
15 contingencies such as the loss of the largest single generating  
16 unit in operation in MAIN will not result in cascading outages  
17 or the dropping of customer load.

18 Q. Are you saying then that the Company and other member utilities  
19 attempt to not only project the load requirements of their  
20 customers and to meet that load, but also attempt to be capable  
21 of responding to reasonably foreseeable contingencies without  
22 interruption of service to the customers?

23 A. That is correct.

24 Q. Are you sponsoring any exhibits as part of your testimony on  
25 forecasted system generation and purchased power?

26 A. Yes. I am sponsoring Exhibits A-3 (TPL-3) through A-7 (TPL-7)  
27 and Exhibit A-9 (TPL-9).

28 Q. Were these exhibits prepared by you or under your direction?

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1 A. Yes.

2 Q. Please identify and describe Exhibit A-3 (TPL-3).

3 A. Exhibit A-3 (TPL-3) indicates the 2006 projected monthly output  
4 and fuel cost for each generating facility on the Wisconsin  
5 Electric system.

6 Q. Please identify and describe Exhibit A-4 (TPL-4).

7 A. Exhibit A-4 (TPL-4) shows the monthly summary of projected  
8 megawatt hour production and fuel consumption and cost by  
9 various fuel types as well as the summary of these factors for  
10 the year 2006.

11 Q. Please identify and describe Exhibit A-5 (TPL-5).

12 A. Exhibit A-5 (TPL-5) indicates the forecast of annual  
13 interchange energy purchases and sales for the years 2006  
14 through 2010.

15 Q. Do you consider these exhibits to represent a reasonable  
16 forecast for 2006 through 2010?

17 A. Yes, I do. The forecast techniques are those utilized in  
18 planning and budgeting the Company's operations and utilize up-  
19 to-date assumptions and data. Results were reviewed and deemed  
20 reasonable by Commodity Resources staff and me.

21 Q. Returning to Exhibit A-5 (TPL-5) please describe the terms  
22 "Firm Purchases - Specific", "Firm Purchases - Undesignated",  
23 "Renewable", "Net MISO Transactions" and "Firm Transmission  
24 Service Cost".

25 A. The term "Firm Purchases - Specific" refers to signed contracts  
26 in place in the designated years for power purchases from  
27 others. More detail on these contracts is provided in Mr.  
28 Schumacher's Exhibit A-14 (PDS-2).

1 "Firm Purchases - Undesignated" refers to additional power  
2 purchases needed to meet system requirements including  
3 reserves. These are "undesignated" at this time because the  
4 power purchase contracts have not yet been negotiated.

5 The term "Renewable" refers to the purchase of energy which  
6 comes from natural resources that do not diminish with use—they  
7 are naturally and continually replenished. Renewable energy  
8 sources, such as the sun, wind, water and biomass, offer a  
9 number of benefits. They produce lower or no air emissions,  
10 little or no solid wastes, and less land disruption when  
11 compared to coal, natural gas or nuclear power plants.

12 The term "Net MISO Transactions" refers to energy purchased  
13 and/or sold into the MISO energy market.

14 "Firm Transmission Service Cost" refers to contracts with  
15 transmission providers to allow for the uninterrupted flow of  
16 purchased power through transmission lines of others to reach  
17 the American Transmission Company, LLC ("ATC") facilities. More  
18 detail on these contracts is provided in Mr. Schumacher's  
19 Exhibit A-14 (PDS-2).

20 Q. Does the Company contemplate any firm purchases or sales in  
21 2006 involving capacity charges for periods in excess of six  
22 months?

23 A. Yes. Mr. Schumacher's testimony and exhibits provide support  
24 for the capacity purchases needed to meet the capacity  
25 requirements shown on Exhibit A-9 (TPL-9) and the firm sales of  
26 capacity.

27 Q. Have you provided the Company's capacity plan for the period  
28 2006 - 2010?

- 1 A. Yes. Exhibit A-9 (TPL-9) shows the calculation of the Company's  
2 capacity requirement for the years 2006 - 2010.
- 3 Q. Are there any additions or retirements of Company generation  
4 currently on-going or scheduled?
- 5 A. Yes. As part of the Company's "Power the Future" ("PTF")  
6 plans, the first unit at the Company's Port Washington  
7 Generating Station, totaling 545 megawatts was placed in  
8 service in July 2005.
- 9 Q. Does the Company plan any generating unit outages of more than  
10 90 days in duration during 2006?
- 11 A. Yes. During the Spring of 2006 the Company has scheduled 14  
12 week outages for units 1 and 2 at the Concord Generating  
13 Station for generator rotor inspection and unit overhaul. The  
14 units are expected to be back in service in May 2006. The  
15 Company has also scheduled a 95 day outage at the Port  
16 Washington Generating Station to begin November 2006 and end  
17 February 2007. This outage is required to tie in the  
18 circulating water system needed for the second unit at this  
19 location scheduled to go in service in 2008.
- 20 Q. Do the exhibits which you are sponsoring reflect the cost of  
21 sulfur dioxide (SO<sub>2</sub>) emission allowances, fuel handling and ash  
22 disposal costs and dry cask storage for spent nuclear fuel?
- 23 A. Yes. The exhibits include the cost of sulfur dioxide (SO<sub>2</sub>)  
24 emission allowances estimated at \$35,708 for the year Fuel  
25 handling and ash disposal and dry cask storage for spent  
26 nuclear fuel are not included in the power supply costs.

1 Q. Please describe briefly the procedure by which the forecasts  
2 and projections identified in Exhibits A-3 (TPL-3) through A-6  
3 (TPL-6) are prepared.

4 A. Commodity Resources distributes the generation requirements  
5 among the various power plants on an economic loading basis  
6 utilizing computer programs which consider such factors as firm  
7 purchase or sale commitments, scheduled outages, forced outage  
8 experience, estimates of MISO energy market activity, additions  
9 or subtractions of generating resources, unit heat rate,  
10 estimated fuel costs, etc.

11 Q. Please identify and describe Exhibit A-6 (TPL-6).

12 A. Exhibit A-6 (TPL-6) indicates for each of the years 2006  
13 through 2010 the anticipated output of the Company's generating  
14 plants, fuel usage and fuel cost, anticipated interchanges and  
15 associated costs.

16 CUSTOMER-OWNED GENERATING SYSTEMS

17 Q. Does the Company purchase power from any customer-owned  
18 generating systems?

19 A. Yes. The Company offers two tariffs for customer-owned  
20 generating systems.

21 Q. Please indicate and describe each tariff.

22 A. The COGS2 tariff is for generators that are rated at 20 kW or  
23 less. The Company purchases output in excess of the customers'  
24 needs from these small generators. There are approximately 64  
25 customers on this tariff generating power from wind, hydro,  
26 methane and other sources. The energy purchased from them at  
27 the COGS2 rate represents less than 0.1% of system  
28 requirements.

1 The COGS1 tariff is for generators that are rated over 20 kW.  
2 This tariff consists of a variety of mid-size to larger  
3 customer-owned generation systems ranging in size from about  
4 100 kW to over 10 MW. Purchases of output from these customers  
5 are made using the COGS1 rate negotiated contracts. The  
6 sources of energy for these generators include landfill gas,  
7 wind, hydro, agricultural waste and municipal waste. The  
8 company will purchase approximately 135,600 MWH of energy from  
9 these 16 customers in 2006. In aggregate this represents less  
10 than 1% of the system requirements.

11 Q. Are the renewable energy purchases for the "Energy for  
12 Tomorrow" program included in this case?

13 A. No, the purchase of renewable energy for use by customers that  
14 are participating in the Company's experimental "Energy for  
15 Tomorrow" program, which was approved by the Commission, on  
16 November 16, 1999, in Case No. U-12099, are not included in  
17 this case. The incremental cost of renewable energy is charged  
18 directly to the customers on the program as a rider. The  
19 energy purchased for the "Energy For Tomorrow" program is  
20 primarily from our COGS customers.

21 RENEWABLE ENERGY

22 Q. Is the Company planning to increase the amount of renewables in  
23 its generation portfolio?

24 A. Yes. In February 2000, Wisconsin adopted a renewable portfolio  
25 standard ("RPS") as part of Act 9. RPS requires Wisconsin  
26 state utilities to provide an increasing percentage of their  
27 energy sold to retail customers from renewable sources. RPS  
28 requires that 0.5% of total Wisconsin retail sales be provided

1 from renewable energy sources in 2001, ramping up to 2.2% by  
2 year 2011. For years 2005 and 2006 the RPS requirement is 1.2%  
3 and increases to 1.55% for years 2006 and 2007.

4 In December 2002, the Company issued a request for proposals  
5 for up to 200 megawatts of wind generation in an effort to  
6 reach its target of at least five percent of retail electric  
7 sales coming from renewable resources by 2011 as part of its  
8 "PTF" initiative.

9 In July 2003, the Company signed 20-year power purchase  
10 agreements with two developers for the entire electricity  
11 output of three wind farms planned to be built in Wisconsin.

12 Since signing these agreements, the Company purchased the  
13 development rights for two of the wind farms from one  
14 developer. It is expected that these two wind farms as well as  
15 the third wind farm to be built by the other developer will be  
16 in service in 2007, pending regulatory approval. The cost of  
17 these three wind farms are not included in the 2006 PSCR plan.

18 In August 2003, the Company issued a request for proposals for  
19 up to 25 megawatts of electricity from "biomass" technologies.  
20 Biomass technologies include organic materials such as  
21 agricultural manure, food processing waste, bio-waste, brewery  
22 residues, organic sludge and crops grown specifically for  
23 energy production purposes. The Company has signed agreements  
24 with two dairies located in Wisconsin to purchase electricity  
25 produced from agricultural manure. One dairy began delivery of  
26 electricity to the Company in August of 2005. The second dairy  
27 is expected to begin in 2006.

28 LOAD MANAGEMENT PROGRAMS

1 Q. Does the Company have interruptible service rates on its  
2 system?

3 A. Yes.

4 Q. Please describe such service and its use in system operation.

5 A. In the Wisconsin retail area, the Company offers three general  
6 primary service rates for 15-minute integrated demands of 1,000  
7 kilowatts interruptible or greater, Cp2V, Cp2M and CPFN.  
8 Cp2V provides the Company with the ability to interrupt such  
9 service when situations occur which reduce the Company's  
10 available capacity or reserve levels below acceptable values.  
11 The rate provides for no more than 150 hours of interruption  
12 per year. An interruption is credited as the actual time of  
13 interruption or four hours, whichever is greater.

14 Cp2M provides the Company with the ability to interrupt such  
15 service during periods of operating capacity or reserve  
16 deficiency and for system energy economy constraints. The rate  
17 provides for no more than 300 hours of interruption per year.  
18 An interruption is credited as the actual time of interruption  
19 or six hours, whichever is greater. Cp2M requires customers to  
20 be 100 percent interruptible.

21 CPFN is similar to Cp2M with the exception that it allows  
22 customers to select a level of firm load as long as they have  
23 at least 1,000 kW of interruptible load.

24 Q. How many customers are served on each interruptible rate?

25 A. As of September 2005, no customers are on rate Cp2V, 16  
26 customers are served on rate Cp2M and 3 customers are served on  
27 rate CPFN.

1 Q. How often are the interruptible customers typically  
2 interrupted?

3 A. Interruptions averaged 0.0 capacity related and 0.2 economy  
4 related interruptions per year for the five years ending in  
5 2005. In 2001, 2002, 2003 and 2004 there were zero hours of  
6 capacity and zero hours of economic interruptions. In 2005,  
7 there were six hours of economic interruptions and zero hours  
8 of capacity interruptions.

9 Q. Does the Company also offer curtailable service rates?

10 A. Yes.

11 Q. Please describe the general primary curtailable service rate  
12 and its use in system operation.

13 A. The Company offers a general primary curtailable service rate  
14 for customers with a minimum of 500 kW of curtailable load.  
15 The rate provides for a maximum individual curtailment period  
16 of eight hours and no more than 300 hours of curtailment per  
17 year. A curtailment is credited at the actual time of  
18 curtailment or four hours, whichever is greater. This service  
19 is utilized during periods of operating capacity or reserve  
20 deficiency and for daily operating economy.

21 Q. How many customers are served on curtailable rates and how  
22 often have they been curtailed?

23 A. In 2005, there were 48 customers, (4 of which were in  
24 Michigan) served on curtailable rates. Two other Michigan  
25 customers have contracts with a curtailable option. During  
26 2001, 2002 and 2004 there were no curtailments. In 2003,  
27 there were two capacity related curtailments for a total of 16

1 hours. In 2005, there was one economic curtailment for six  
2 hours.

3 BULK POWER OPERATIONS

4 Q. Please describe the responsibility of the Company's Power  
5 Trader.

6 A. The Power Trader forecasts system loads, evaluates generation  
7 availability and market opportunities, and develops a dynamic  
8 plan to reliably meet, at minimal system costs, the real time  
9 and near term electric load requirements of the Company.

10 Q. How does the Power Trader project what load conditions will  
11 occur over the next 24-hour period?

12 A. The Power Trader uses a load-forecasting program that  
13 integrates forecasted weather, calendar and historic data and  
14 simulates and calculates the various factors and conditions  
15 which affect load levels. The program produces an hour-by-hour  
16 projection of system load levels for the next seven days.

17 Q. How does the Power Trader minimize the cost of producing  
18 electric energy?

19 A. This is done by effectively and continuously assessing and  
20 utilizing available resources, including company-owned or  
21 contracted generating assets, load assets, MISO and PJM energy  
22 market transactions, transmission resources, and load  
23 management programs. The Power Trader is supported by  
24 sophisticated computer hardware and software programs that  
25 identify which resources should be utilized for minimum overall  
26 cost. These programs consider such factors as unit heat rates,  
27 unit fuel costs, ramp rates, maximum and minimum operating  
28 levels, as well as minimizing market operations costs.

1           Typically the operating plan for a given day is defined  
2           on a rough basis several days in advance. It is more precisely  
3           tuned the day before it is to go into effect.

4           In developing the production plan for a given day, the  
5           Power Trader will forecast system load, create load bids,  
6           evaluate generation availability, and maintain and update  
7           generation resource offers. Thus, an operating plan is created  
8           for the following day. This information is also given to MISO  
9           who operates a bid/offer based energy market using constrained  
10          economic dispatch to produce locational marginal prices for the  
11          market footprint.

12       Q. You have described how the Power Trader plans for the next  
13       day's operation. How does he/she operate "today"?

14       A. The Power Trader utilizes the operating plan prepared the  
15       previous day and makes any modifications necessary to  
16       accommodate changes which have occurred. Aided by the  
17       computerized, automatic generation control system, the Power  
18       Trader works with Electric System Operations personnel to  
19       schedule generating units on- and off-line and load the units  
20       according to MISO energy market results. In response to  
21       increases and decreases in load, the automatic generation  
22       control system adjusts loading on generating units to achieve  
23       minimum system production costs at all times, consistent with  
24       equipment constraints, the MISO energy market and available  
25       transmission.

26       On a real time basis, the Power Trader updates generation  
27       resource offers, monitors the MISO energy market and continues  
28       to adjust the operating plan for the day.

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1 Q. How does the Power Trader utilize load management programs for  
2 daily operating economy?

3 A. Included in the resources available to the Power Trader for  
4 minimizing overall system costs are numerous load management  
5 programs. While some programs are limited to capacity  
6 constraint situations and can only be utilized to avoid  
7 capacity shortfalls, others are designed to provide economic  
8 signals to customers to remove load from the system. These  
9 "economic" load management programs include a variety of  
10 programs offered to varying customer classes with both fixed  
11 and varying cost or incentive structures. The Power Trader is  
12 able to utilize these programs when it is economical to do so  
13 rather than to purchase more expensive energy.

14 Q. Is it your evaluation that the Company's decisions to provide  
15 power supply in the manner described in your testimony are  
16 reasonable and prudent?

17 A. Yes, in my opinion such decisions are reasonable and prudent.

18 COAL PROCUREMENT

19 Q. You have described the first two general steps used to project  
20 system fuel costs, namely the sales forecast and the projected  
21 operation of the generating system. Now please describe in  
22 more detail how delivered fossil fuel costs are projected. In  
23 particular, what are the Company's coal procurement practices?

24 A. The Company believes that flexibility and a pragmatic approach  
25 are essential elements in effective fuel procurement. These  
26 considerations have minimized the need for rigid formalized  
27 policy directives on the subject of fuel procurement. Matters  
28 of fuel procurement are continually reviewed and resolved at

1 senior management levels. The Coal Resources Section is  
2 responsible for procuring fossil fuels. The basic  
3 instructions to the Coal Resources Section are to maintain a  
4 sufficient inventory of coal within the scope of Company  
5 requirements and fuel market and transportation uncertainties.

6 Q. How does the Company contract for coal purchases?

7 A. Coal purchases are generally classified into three categories:  
8 long-term, intermediate term, and spot purchases. Long-term  
9 is considered to involve periods of more than five years.  
10 Long-term contracts have encouraged coal producers to dedicate  
11 reserves to meet the total contract tonnage, provide assurance  
12 of operation and also aid the producer in securing financing.  
13 These and other advantages afforded by long-term sales  
14 contracts enable the Company to contract an assured delivery  
15 and more consistent coal quality than one expects from several  
16 smaller agreements. In times of escalating inflation and  
17 tightening market trends, spot market prices rise to a level  
18 above older term agreements. During times of tight markets,  
19 spot coal quality deteriorates as prices increase. The last  
20 twelve months have generally seen dramatic price increases for  
21 sub-bituminous spot coal purchases, while bituminous spot coal  
22 prices have increased at a lower rate. This market behavior  
23 has reinforced the Company's interest in staggered, long-term  
24 contracts because it assures the source of supply with a known  
25 quality and anticipated cost level. An assured volume from  
26 one origin for a definitive period also provides for lower  
27 transportation charges.

1           Short, or intermediate term contracts, are generally  
2           considered to cover one to five year periods and are typically  
3           used to construct a portfolio of contracts that will more  
4           closely track "market" pricing. The use of intermediate term  
5           contracts is increasing for Wisconsin Electric because many  
6           coal suppliers are unwilling to commit to long term agreements  
7           in an environment of increasing spot prices.

8           Spot purchases do not normally play a significant role in  
9           fuel procurement. However, the Company has seen higher than  
10          forecast coal burns under MISO and has continued to suffer  
11          supply interruptions in the last 12 months because of rail  
12          transportation problems which has led to more spot purchases.  
13          Spot purchases are generally for one shipment of 20,000 tons,  
14          or less or for a determined volume over a period of less than  
15          a year.

16   Q.   Do the Company's contracts have varying lengths of duration?

17   A.   Yes, the Company currently has ten contracts ranging from one  
18          to twenty years in their original length, plus one spot  
19          contract.

20   Q.   Are you sponsoring an exhibit in connection with your  
21          testimony on fuel procurement?

22   A.   Yes, I am sponsoring Exhibit A-8 (TPL-8).

23   Q.   Was this exhibit prepared under your direction?

24   A.   Yes.

25   Q.   Does Exhibit A-8 (TPL-8) list the Company's current coal  
26          contracts you referred to previously?

1 A. Yes, Exhibit A-8 (TPL-8) codes the identity of Wisconsin  
2 Electric's coal contract suppliers and lists the date of  
3 expiration and the 2006 delivered price.

4 Q. Does the Company use systematic procedures for periodic market  
5 investigations of fossil fuel costs and availability,  
6 particularly prior to renewal or re-negotiation of contracts?

7 A. Yes, the Company relies on extensive direct contacts with coal  
8 companies throughout the country, transportation companies'  
9 coal departments, data collected from current periodicals,  
10 trade journals, purchased research reports from coal market  
11 consultants, over-the-counter coal trades and options posted  
12 by coal traders, and other coal consuming companies for these  
13 market investigations.

14 Q. When the Company prepares a bidder's list for coal suppliers,  
15 what criteria are used in preparing such a list?

16 A. A formal bidder's list for securing proposals is not prepared  
17 in advance. For long-term contracts, written invitations are  
18 made to producers that have a production capacity or reserves  
19 capable of development that appear to have a quality product  
20 equal to the Company's requirements. Information is  
21 maintained on potential new suppliers that have the required  
22 capability and they, too, are advised of the Company's long-  
23 term purchase needs. Producers that are known to have a  
24 former experience of noncompliance to contract terms, such as  
25 annual volumes or quality, are not normally invited to submit  
26 proposals.

27 Intermediate term contracts of one to five years are  
28 solicited in the same manner as long-term contracts. The coal

1 industry is generally familiar with the Company's purchasing  
2 practices. Producers unfamiliar with these practices are  
3 advised of Wisconsin Electric's procedures and invited to  
4 formalize their interest at the appropriate times.

5 To receive serious consideration, a proposal is required  
6 to be in written form describing the properties of the subject  
7 fuel and the proposed terms and conditions.

8 Q. How does the Company select potential fuel suppliers?

9 A. The selection of potential suppliers is made on the knowledge  
10 of the producer's capability, reliability, quality of product,  
11 and historical operating cost.

12 Q. How does the Company select the successful bidder on long-term  
13 contracts?

14 A. The selection of long-term suppliers involves an evaluation of  
15 reserve status, reliability of production and quality of  
16 product that is compatible with the power plant equipment and  
17 environmental regulations. The final procurement decision is  
18 determined by a comparison of bid evaluation of mine price,  
19 quality guarantee, cost of by-product disposal, performance  
20 assurance, contract terms and conditions, and delivered cost,  
21 including transportation.

22 Intermediate term contracts are selected in the same  
23 manner as long-term contracts.

24 Q. What practices are taken to minimize cost to the Company?

25 A. The Coal Resources Section's primary objective is to obtain  
26 coal supplies in quantity and quality sufficient to meet the  
27 needs of the coal-fired generating plants in an economical  
28 manner and consistent with environmental constraints. In

1 addition to negotiating the most advantageous contracts  
2 possible, prices and quality of coal are continually  
3 monitored. Every price change requested by a supplier must  
4 comply with the terms of the purchase contract and further  
5 must be substantiated with the required supporting  
6 documentation. The Coal Resources Section reviews each price  
7 change request. If there is an area of question in the  
8 supplier's documentation, this question is resolved by a mine  
9 visit to obtain additional data, or an audit is conducted by  
10 Company auditors or an outside auditing firm. Where there is  
11 a question of a technical nature the Company may employ a mine  
12 engineering or consulting firm to review the supplier's data.

13 Each coal purchase agreement contains a provision that  
14 guarantees the heat value. Older contracts also contain an  
15 ash content guarantee. More recent contracts require the heat  
16 and ash content guarantee along with a maximum allowable SO<sub>2</sub>  
17 content. Coal that is received having other than the  
18 guaranteed qualities may have a premium or penalty assessment  
19 where applicable under the terms of a contract for heat,  
20 sulfur and/or ash content, as well as provisions for rejection  
21 of coal that does not meet the minimum heat content guarantee  
22 or exceeds the maximum ash or sulfur guarantees.

23 Procedures for the sampling and analyzing of coal  
24 deliveries vary with each coal supply. Sampling of the coal  
25 is typically done at the mine loading site or at the rail  
26 transfer docks by the coal supplier or an independent sampling  
27 Company. The coal samples are then typically analyzed by the

1 supplier or a third party laboratory and a sample is forwarded  
2 to the Company for analysis.

3 Each analysis is reviewed by the Coal Resources Section  
4 for quality compliance. If the analyses indicate an inferior  
5 coal is being shipped, the supplier is contacted and a remedy  
6 is arranged. Should poor quality determination continue, the  
7 supplier is shut off from further shipment until the Company  
8 is assured the problem has been corrected.

9 In conjunction with the purchase of coal, transportation  
10 rates and conditions are simultaneously determined. The  
11 Company's contracts hold the shipper responsible for  
12 additional freight charges assessed for failure to meet tariff  
13 or contract loading specifications. All Company rail  
14 shipments move under contracts with rate adjustment formulas  
15 and are not subject to Interstate Commerce Commission Ex Parte  
16 No. 290 (Sub-No. 2) rate adjustments.

17 Q. In general, how are coal tonnage requirements determined?

18 A. The Regulatory Affairs and Policy Department develops the  
19 forecast of system demand and energy requirements. The  
20 Commodity Business Unit then distributes the general  
21 requirements among the various power plants on an economic  
22 loading basis which then determines the volume of fuel  
23 required to meet the generation schedule. The fuel  
24 requirement projections are then forwarded to the Coal  
25 Resources Section for planning and acquisition.

26 Q. Were these fuel consumption projections incorporated in  
27 Exhibit A-6 (TPL-6)?

1 A. Yes. Exhibit A-6 (TPL-6) includes the consumed coal cost in  
2 dollars per million BTU ("MMBTU") by year for a five-year  
3 period for each coal burning power plant.

4 Q. What procedure was used to determine the cost per MMBTU in  
5 Exhibit A-6 (TPL-6)?

6 A. Projected cost per MMBTU for each power plant shown on  
7 Exhibit A-6 (TPL-6) for 2006 take into consideration the price  
8 adjustment provisions and date of change along with the  
9 monthly volume of coal receipts. The more sophisticated coal  
10 contacts can include numerous items of cost that can be  
11 adjusted. In some cases, the cost items are adjusted monthly,  
12 while other items may be quarterly, semi-annually or annually.  
13 In order to prepare the budget, the Coal Resources Section  
14 must estimate the date and amount of price changes, tonnage  
15 affected, and premium or penalty quality adjustments. These  
16 are repetitious computations since some cost items represented  
17 by government published indexes are reviewed every 90 days.  
18 For example, wage increase automatically triggers  
19 corresponding increases in holiday pay, vacation pay, welfare  
20 fund payments, sick leave, and all other similar costs  
21 associated with daily wage costs. The costs shown in Exhibit  
22 A-6 (TPL-6) for the period 2006-2009 were developed by  
23 adjusting economy.com projections for inflation to reflect its  
24 historical relationship with Wisconsin Electric's actual  
25 delivered coal prices.

26 NATURAL GAS AND OIL PROCUREMENT

27 Q. How does the Company procure natural gas and oil for  
28 generation?

1 A. Since a significant portion of the Company's gas fired  
2 generation is peaking capacity, called upon to run only after  
3 lower cost resources are already utilized, there can be  
4 significant uncertainty regarding the timing and quantity of  
5 natural gas consumption for electric generation. Because of  
6 this uncertainty, much of the Company's gas procurement must  
7 be in the daily and intra-day cash market. It would be highly  
8 speculative to make large quantities of natural gas purchases  
9 far in advance of an uncertain need. Based upon the  
10 production plan developed by the Power Trader, the Gas  
11 Resources group acquires natural gas through the combination  
12 of spot purchases and monthly term/baseload purchases. The  
13 Company solicits pricing proposals from multiple suppliers  
14 when seeking additional gas purchases and selects the lowest  
15 cost option, taking into consideration counter party credit  
16 issues and reliability concerns. This results in the most  
17 economical purchase plan for natural gas because of the  
18 variable and unpredictable amount of incremental load for  
19 which natural gas is utilized.

20 Oil is acquired through the use of spot purchases and bulk  
21 purchases stored in local terminals.

22 Q. What share of generation is met using natural gas and oil?

23 A. Including igniter usage at coal plants and the addition of the  
24 Port Washington combined cycle unit, natural gas and oil will  
25 account for approximately 6 percent of the energy generated  
26 (in MWH) by the Company, and approximately 28 percent of the  
27 Company's owned and leased generating capacity (in MW) in  
28 2006. In addition, the gas purchased for the Alliant Energy

1 Neenah, Calphine Zion and Ameren Elgin plants will provide  
2 595,799 MWH of energy based on capacity of 864 MW in 2006.

3 Q. Does the Company purchase natural gas for any of its purchase  
4 power agreements?

5 A. Yes. The Company's PPAs for the Alliant Energy Neenah, the  
6 Calphine Zion and the Ameren Elgin plants have a tolling  
7 arrangement which allows the Company to purchase and deliver  
8 the natural gas to these plants as part of its natural gas  
9 portfolio. As a benefit, the Company is able to achieve  
10 greater flexibility in natural gas scheduling, resulting in  
11 lowering natural gas costs.

12 Q. Does the Company supply natural gas to the LSP-Whitewater  
13 plant?

14 A. No.

15 Q. What is the impact of natural gas and oil costs in 2006?

16 A. The Company forecasted the use of 14.8 million MMBTU of  
17 natural gas in 2006 at \$10.87/MMBTU, for a total estimated  
18 cost of approximately \$161.2 million. The Company forecasted  
19 the use of 1,103,000 gallons of fuel oil in 2006 at \$1.97 per  
20 gallon, for a total estimated cost of approximately \$2.2  
21 million. Forecasted gas usage at, the Alliant Energy Neenah,  
22 the Calphine Zion and Ameren Elgin plants for 2006 is 5.2  
23 million MMBTU at \$9.90/MMBTU, for a total projected cost of  
24 approximately \$51.5 million.

25 Q. In its 2006 PSCR plan the Company has included costs for a  
26 natural gas risk management hedging program for gas-fired  
27 generation. What is the basis for this hedging program, its  
28 intent and how does it benefit utility customers.

1 A. As a result of revisions to the Wisconsin Administrative  
2 Code(ch. PSC 116, Electric fuel rules), utilities in  
3 Wisconsin, may begin to include the costs and benefits of fuel  
4 price risk management hedging tools in their fuel costs,  
5 provided the Public Service Commission of Wisconsin ("PSCW")  
6 has approved a risk management plan.

7 The intent of the program is to mitigate and protect against  
8 natural gas price spikes. The cost of the risk management  
9 hedging program is equivalent to an insurance premium against  
10 higher price spikes. Given the recent high gas prices, high  
11 volatility and concerns about storage and supply/demand  
12 imbalances, the Company believes it is important to protect  
13 customers from future price swings. While managing gas price  
14 risk does not equate to guaranteed savings, financially  
15 settled hedging can act like insurance and be a proper and  
16 prudent action when a negative event such as a price spike  
17 occurs.

18 Q. What is the amount for risk management plan that the Company  
19 is requesting to be included in its 2006 PSCR plan?

20 A. The Company has projected a cost of \$5,775,235 for the 2006  
21 PSCR plan.

22 Q. In your opinion, are the Company's fossil fuel purchasing  
23 policies and practices reasonable and prudent?

24 A. Yes, I believe they are and that the Company has taken  
25 appropriate actions to minimize costs.

26 **NUCLEAR FUEL PROCUREMENT**

27 Q. Would you please provide a brief description of the steps  
28 involved in procurement of nuclear fuel?

1 A. Uranium is the element which is ultimately the source of  
2 nuclear energy. Before it can be utilized as nuclear fuel,  
3 however, it must be modified from its naturally-occurring form  
4 of  $U_3O_8$ . Wisconsin Electric purchases  $U_3O_8$  as a mined raw  
5 material and has it delivered to a conversion facility, where  
6 the form of the uranium component is "converted" by a chemical  
7 process from  $U_3O_8$  to  $UF_6$ . The  $UF_6$  is then delivered to an  
8 enrichment facility for enrichment. The product of the  
9 enrichment process, enriched  $UF_6$ , is delivered to a fuel  
10 fabricator. The enriched  $UF_6$  is then processed into pellets  
11 which are loaded into sealed metal rods. The sealed rods are  
12 assembled into the fuel assembly structure, and the completed  
13 assemblies are delivered to the nuclear plant site for loading  
14 into the reactor. In order to accomplish the steps leading up  
15 to delivery of nuclear fuel to the plant site, the Company has  
16 separate contracts for purchase of  $U_3O_8$ , conversion to  $UF_6$ ,  
17 enrichment of  $UF_6$ , and fabrication of fuel assemblies. In some  
18 cases, there will be more than one contract for each of the  
19 above processing stages.

20 Q. What is the basis for the amount of nuclear fuel purchased?

21 A. The length of the upcoming operating cycle is determined and is  
22 currently based on a nominal 18 months of operation. From the  
23 length of the operating cycle and plant parameters (such as  
24 plant efficiency, minor outage rate, etc.), the amount of  
25 energy required to be produced by the reactor core is  
26 determined. From the energy requirements, a core design is  
27 developed to meet that energy requirement while meeting all of  
28 the safety parameters for the safe operation of the plant.

1 This core design establishes the number of fuel assemblies at a  
2 given enrichment that must be loaded into the reactor core to  
3 support the plant operation. The number of assemblies  
4 typically loaded into the reactor core ranges from  
5 approximately 36 to 48, and is referred to as a "region" of  
6 fuel.

7 Q. How are the nuclear fuel costs and nuclear generation  
8 determined?

9 A. On November 23, 1999, Wisconsin Electric signed an operating  
10 services agreement with the Nuclear Management Company, LLC  
11 ("NMC"). The agreement calls for the NMC to provide services  
12 to cover all plant operations, including fuel procurement and  
13 accounting services. It is the responsibility of the NMC  
14 Nuclear Fuel Business Systems and Nuclear Fuel Commodities  
15 Groups to determine both actual and projected data for  
16 calculation of nuclear fuel costs. This data consists of  
17 region acquisition costs and monthly thermal generation  
18 statistics for the Company's nuclear units. The thermal  
19 generation is converted into equivalent Btu's and megawatt-hour  
20 generation using formulas and plant efficiencies and then  
21 provided to Commodity Resources.

22 Q. On what basis are nuclear fuel acquisition costs forecasted?

23 A. To the extent that there is nuclear fuel in process at any  
24 stage, the actual cost is allocated to a region on a first-in,  
25 first-out ("FIFO") basis in accordance with projected  
26 requirements. Additional requirements are then filled and  
27 priced, again on a FIFO basis, in accordance with the quantity  
28 and pricing provisions of existing contracts. Remaining

1 requirements, if any, are filled and priced on the basis of  
2 estimated market prices at the time of the requirement.

3 Q. Please describe the major active contracts for the purchase of  
4 nuclear fuel to support plant operations for the period 2006  
5 through 2010, including percentage of total requirements  
6 covered and duration of contracts.

7 A. Contract coverage and other supply arrangements for nuclear  
8 fuel for the Company's reactors are presented in Exhibit A-10  
9 (TPL-10). The exhibit identifies the sources projected to  
10 support plant operations for the period 2006 through 2010. The  
11 percentage of requirements is based upon the Company's total  
12 purchase requirements for the period 2006 through 2010. The  
13 expected years of delivery identifies those years in which each  
14 source is projected to deliver a fuel cycle service.

15 Q. How does the Company plan to satisfy uranium requirements  
16 during the 2006 through 2010 period?

17 A. The Company has a long term contract with Energy Resources of  
18 Australia which will provide 38% of the requirements for the  
19 years 2006-2010. The contract with Energy Resources of  
20 Australia ("ERA") provides for the extension of the contract  
21 for up to two additional years at the sole discretion of  
22 Wisconsin Electric. This option must be exercised one year  
23 prior to the expiration of the current contract (2007). The  
24 contract will be evaluated against the current prevailing  
25 market conditions at that time and the decision on whether or  
26 not to exercise the optional extension will be decided at that  
27 time. In addition to the supply contract with ERA, the NMC has  
28 entered into two additional contracts that will provide a

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1 supply of uranium. The contracts are with UG U.S.A. for 6% and  
2 with Areva for 8% of the requirements for the Point Beach  
3 plant.

4 Q. What are the Company's current arrangements for the supply of  
5 conversion services for 2006-2010?

6 A. In 2001, a contract for conversion for the period 2003-2005 was  
7 signed with Cameco by the NMC on behalf of the member  
8 utilities, including the Company. In 2003, the NMC signed a  
9 conversion contract with ConverDyn on behalf of the member  
10 utilities, including the Company. This contract was amended in  
11 2005 for additional supply through 2010. This contract will  
12 supply an additional 16% of the required conversion for the  
13 Company during the period 2006-2010. Additional contracts have  
14 been signed with UG U.S.A. for 7% and with Areva for 8% of the  
15 requirements for the Point Beach plant. Conversion  
16 requirements during the period 2006-2010 are not completely  
17 covered by contract. The uncovered requirements through 2010  
18 represent 69% of the total conversion services requirements for  
19 the years 2006-2010. The forecasted conversion costs for this  
20 material assumes spot market prices.

21 Q. What arrangements has the Company made for the supply of  
22 enrichment services?

23 A. In 1998, the Company contracted with the United States  
24 Enrichment Corporation ("USEC") for supply of 29% of the  
25 Company's requirements for enrichment services for 2006-2010.  
26 The contract with USEC expires in 2006. In late 2004, the NMC  
27 signed a contract with Urenco on behalf of the member

1 utilities, including the Company. The Urenco contract will  
2 supply 35% of the requirements of the Point Beach plant through  
3 2010. The uncovered enrichment services requirements for 2007  
4 through 2010 represent the remaining 36% of the total  
5 requirements for 2006-2010. The forecasted enrichment services  
6 costs assume the projected spot market price.

7 Q. To what extent has the Company covered its fuel fabrication  
8 requirements during the 2006-2010 period?

9 A. In 1991 the Company negotiated a modification to an existing  
10 contract with Westinghouse Electric Corporation to cover all  
11 fabrication services for both units of the Point Beach nuclear  
12 plant through the end of their current operating licenses (2010  
13 and 2013).

14 Q. What specific actions are being taken to reduce or control the  
15 cost of nuclear fuel?

16 A. Among the actions which have served, or will serve, to reduce  
17 the cost of nuclear fuel are the following:

- 18 1. The Company currently has a uranium supply contract which  
19 provides 38% of the Company's total requirements over the  
20 2006-2010 period with an option to extend the contract to  
21 cover up to 100.0% of the Company's requirements through  
22 2009, at prices that are based on a discount from the spot  
23 market price at the time of delivery. The magnitude of the  
24 discount increases with increasing spot market prices,  
25 thus ensuring protection in both rising and falling market  
26 conditions. The terms and conditions of this contract  
27 were renegotiated in 2000 to increase the discount for all  
28 future deliveries.

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- 1        2.    The NMC, on behalf of the Company, has been evaluating and  
2            contracting for supply of uranium and conversion services  
3            from industry brokers and traders to (1) provide for  
4            additional security of supply based on industry events  
5            over the last few years that have caused supply  
6            disruptions and (2) to address the recent rapid increase  
7            in uranium spot market prices (\$20.25 per pound in October  
8            200~~4~~ to \$30.20 per pound in August 2005).
- 9        3.    The variable tails assay option ("VTAO") provided in the  
10            Company's enrichment contracts has been utilized both for  
11            reduction of the unit cost of enriched product and for  
12            control of in-process inventory levels.
- 13       4.    In 1998, the Company executed a contract with the  
14            privatized USEC at a significant cost reduction from the  
15            pricing afforded by the Utility Services Contract ("USC")  
16            with the US Department of Energy ("DOE") and USEC as a  
17            government corporation. Significant cost reductions over  
18            the USC are realized on 29% of total required enrichment  
19            services for the period 2006-2010.
- 20       5.    The NMC, on behalf of the Company, entered into an  
21            enrichment services contract with Urenco in 2004 for  
22            supply from 2006 through 2010. The contract is a base  
23            price escalated contract at favorable terms compared to  
24            today's spot market price. The contract also includes a  
25            price reopener to ensure reasonable enrichment prices are  
26            maintained throughout the duration of the contract. The  
27            Urenco contract will supply 35% of the reload requirements  
28            for the Point Beach plant.

- 1       6.    The Company's current contract for fuel fabrication  
2           provides the ability to employ a fuel assembly which both  
3           reduces nuclear fuel costs and reduces the amount of spent  
4           nuclear fuel generated. Reload regions containing this  
5           fuel assembly were inserted into the Point Beach Unit 2  
6           reactor for the first time in the fall of 2000 and in Unit  
7           1 in the spring of 2001. The new fuel assemblies utilize  
8           new structural materials and increased fuel rod diameter  
9           that will allow for increased energy production capability  
10          per assembly in order to reduce the number of assemblies  
11          replaced at each refueling; this will reduce both the  
12          annual nuclear fuel cost and the number of spent fuel  
13          assemblies which are generated
- 14       7.    In 1994, the Company negotiated a price protection  
15           amendment to the fabrication contract with Westinghouse.  
16           The amendment ensures that the Company's cost of fuel  
17           fabrication services is within 15% of the average prices  
18           of similar Westinghouse fuel products, as determined by  
19           the audit provisions of the amendment.
- 20       8.    The Company utilizes an integrated nuclear fuel planning  
21           and accounting computer system to support its fuel  
22           management activities and facilitate minimizing nuclear  
23           fuel acquisition costs. The system has enhanced the  
24           Company's ability to achieve the most economical fuel  
25           cycle through rapid evaluation of multiple procurement,  
26           fuel loading and utilization alternatives.
- 27       9.    The NMC on behalf of the member utilities, including the  
28           Company, continues to evaluate and contract for additional

1       supply of uranium, conversion services and enrichment  
2       services to fulfill reload requirements based on  
3       expiration of the existing supply contracts.

4   Q.   Please evaluate the reasonableness and prudence of the  
5       Company's policies and methods for providing a nuclear fuel  
6       supply.

7   A.   The primary objective in negotiating and administering nuclear  
8       fuel contracts is an assured supply of a reliable product or  
9       service at a reasonable cost. A contract will not be executed  
10      unless the NMC judges that there is an acceptable level of  
11      confidence that the contract satisfies these objectives. Once  
12      a contract is executed, it is continuously reviewed to ensure  
13      that all advantageous provisions are invoked and that all  
14      beneficial flexibilities are utilized. If circumstances change  
15      after execution of a contract such that the anticipated  
16      benefits have not been, or are unlikely to be, realized, the  
17      Company employs all reasonable efforts to negotiate a  
18      modification which will restore the original intent of the  
19      contract. The ability to predict requirements for nuclear fuel  
20      cycle services is limited by the predictability of nuclear  
21      plant operation, which in turn is impacted by electrical  
22      demand, performance of plant equipment, and actions of  
23      regulatory bodies. While the inability to consistently predict  
24      nuclear fuel requirements results in periodic inventory swings  
25      and imbalances, the Company has consistently met its fuel cycle  
26      delivery requirements and has always had the required number of  
27      fuel assemblies available at the plant site for scheduled  
28      refuelings. The favorable results obtained in fuel procurement

1 activities involving markets which have proven to be both  
2 volatile and unpredictable and the successful measures taken to  
3 control and/or reduce nuclear fuel costs, are considered to be  
4 substantial evidence of the reasonableness and prudence of the  
5 Company's nuclear fuel procurement policies and methods.

6 Q. Is the nuclear fuel owned or leased?

7 A. Nuclear fuel is placed under lease after the fabricated fuel  
8 assemblies are delivered to the plant, but before they are  
9 loaded into the reactor. The fuel remains under lease while it  
10 is in the reactor.

11 Q. How is the fuel accounted for under the nuclear fuel lease?

12 A. The Company sells the nuclear fuel to the Wisconsin Electric  
13 Fuel Trust ("Trust") for the accumulated book cost. The fuel  
14 is then leased by the Company and the cost of the fuel is  
15 amortized over the anticipated fuel burn. In addition to the  
16 cost of the fuel, the payments to the lessor include a lease  
17 finance charge which is primarily the Trust's cost of short-  
18 term commercial paper. In an attempt to levelize the expense  
19 for the lease finance charge over the associated fuel burn, the  
20 total finance payments for a region are estimated on a monthly  
21 basis beginning when the fuel enters the reactor. This total  
22 amount becomes the basis for determining the cost and for  
23 calculating the unit charge to be assessed over the anticipated  
24 fuel burn. The nuclear fuel lease also contains a provision  
25 whereby lease finance costs incurred during a period when the  
26 plant is not operating are deferred. These lease finance costs  
27 are then amortized and paid over the remaining burn of the  
28 fuel.

1 Periodically, adjustments are made to take into account  
2 any changes in the total anticipated costs, the anticipated  
3 fuel burn, and the actual costs expensed. Any over or under  
4 accrual of the costs is then included in the expense over the  
5 remaining fuel burn. As a result, over the life of any given  
6 fuel region, the payments to the lessor for the fuel and lease  
7 costs equal the amount expensed.

8 Q. Are there any other costs associated with nuclear fuel?

9 A. Yes. Nuclear fuel costs also include an estimate for the Spent  
10 Nuclear Fuel ("SNF") disposal fee and the decontamination and  
11 decommissioning of US enrichment facilities.

12 Q. Is the spent fuel disposal component of nuclear fuel costs for  
13 the subject period based on existing contracts?

14 A. Yes it is. On June 16, 1983, the Company entered into a  
15 contract with the DOE for the ultimate disposal of all spent  
16 fuel owned by the Company, pursuant to the provisions of the  
17 Nuclear Waste Policy Act of 1982. Under this contract, the  
18 Company is required to pay an amount of one mill per kilowatt-  
19 hour of net nuclear electrical generation for transportation  
20 and disposal of nuclear fuel which generates electricity.

21 Q. Does the spent fuel disposal component include only those  
22 services which are provided under the Company's contract with  
23 DOE?

24 A. Yes.

25 Q. What is the Company's position on the disposal of spent nuclear  
26 fuel?

27 A. The Company's position is that DOE must move spent nuclear fuel  
28 to a permanent central disposal facility as soon as safety and

1 economy will allow. Wisconsin Electric strongly supports a  
2 permanent national disposal facility at the Yucca Mountain site  
3 and continues to work with the Nuclear Energy Institute and the  
4 Nuclear Management Company towards the licensing and  
5 development of this site. The Company has also filed for  
6 damages in the U.S. Court of Claims for DOE's failure to begin  
7 accepting spent nuclear fuel in 1998 in accordance with the  
8 Standard Contract.

9 POWER THE FUTURE (PTF)

10 Q. What is the Company's PTF proposal?

11 A. On November 29, 2000, Wisconsin Energy Corporation ("WEC")  
12 filed an application with the PSCW regarding its PTF proposal  
13 to assure reliable, economical and environmentally responsible  
14 electric power. Based on input from customer groups and  
15 others, WEC withdrew its original PTF proposal on February 23,  
16 2001, and replaced it with a modified proposal that employs  
17 innovative "leased generation contracts" instead of traditional  
18 PPAs. This modified proposal was filed because the crisis in  
19 the California power market and other problems involving  
20 electric power market deregulation had raised grave concerns  
21 about excessive reliance on PPAs, which are subject to federal  
22 rather than PSCW regulation. Using the lease model, instead of  
23 PPAs, allows WEC to proceed with the construction of  
24 approximately 2,900 megawatts of new generation projects, while  
25 ensuring oversight by the PSCW to protect customers' interests.  
26 The plants will include two 545-megawatt combined cycle natural  
27 gas-fired units identified as the Port Washington Generation  
28 Station ("PWGS") at the Port Washington Power Plant site. And

1 three 600-megawatt coal-fired power units identified as the Elm  
2 Road Generation Station ("ERGS") are planned for the Oak Creek  
3 Power Plant site.

4 Q. Why is the Company proposing to build new power plants?

5 A. In order to assure adequate generation is built to meet the  
6 projected load growth on its system, the Company will need to  
7 either build new power plants or continue to purchase  
8 increasing amounts of power each year. The Company recognizes  
9 that using a diverse fuel mix of nuclear, coal, gas, hydro and  
10 renewable sources, along with purchased power will ensure  
11 adequate, reliable and affordable power. Diverse fuel sources  
12 for power plants enhance long-term fuel price stability and  
13 provide customers with a stable, less costly electricity  
14 supply.

15 Q. What is the status of the Company's PTF proposal?

16 A. The PWGS portion of the PTF initiative received approval from  
17 the PSCW on December 20, 2002 in Docket No. 05-CE-117. PWGS  
18 will be an intermediate load plant, providing electricity  
19 during periods of heavy demand. Earlier this year, Units 4, 5  
20 and 6 of the Port Washington Power Plant were demolished to  
21 make room for the first new PWGS unit. Groundbreaking for the  
22 first unit took place in July 2003, and the unit achieved  
23 commercial operation on July 16, 2005. Demolition of units 1,  
24 2, and 3 of the Port Washington power plant is underway to make  
25 room for the second PWGS unit. Construction of the second unit  
26 is scheduled to commence in earnest in early 2006. This unit  
27 will be ready for service by the summer of 2008.

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1 The ERGS portion of the PTF initiative received approval from  
2 the PSCW for two supercritical pulverized coal ("SCPC")  
3 generating units on November 10, 2003 in Docket No. 05-CE-130  
4 and received an Air Pollution Control Construction Permit from  
5 the Wisconsin Department of Natural Resources on January 14,  
6 2004. Approval for the Integrated Gasification Combined Cycle  
7 (IGCC) generating unit was not received. The CPCN for the SCPC  
8 units was vacated by a Circuit Court on November 29, 2004. On  
9 June 28, 2005 the Supreme Court of Wisconsin reinstated the  
10 CPCN. All major permits and approvals needed to commence  
11 construction were obtained by June 28, 2005. A Mobilization  
12 Notice was issued to Bechtel Power Corporation on June 29, 2005  
13 and site activities commenced on the same day. Full Notice to  
14 Proceed was issued to Bechtel on July 29, 2005. The first SCPC  
15 unit is expected to be in service in 2009 and the second unit  
16 in service in 2010. Therefore the SCPC units will contribute  
17 fuel costs towards system energy costs starting in 2009.

18 Q. Are the projected fuel costs of the new units associated with  
19 PTF included in the PSCR forecast?

20 A. Yes. The projected system fuel costs for 2006 - 2010  
21 incorporate the cost of natural gas and coal associated with  
22 the new PTF units in the same manner as the cost of fuel at  
23 existing Company power plants. With the advent of the PTF  
24 units, power supply costs starting in 2006 will increase at  
25 lower rates than if the Company met its increasing load serving  
26 obligations through additional purchase of power from IPP  
27 facilities, as the PTF units provide more cost effective supply  
28 of power to serve load. Lower projected fuel costs are driven

1 by the PTF design basis for adding fuel diverse, efficient and  
2 low overall cost of new sources of generation. To illustrate  
3 this impact, as shown on Exhibit A-6 (TPL-6), total system  
4 energy costs actually decrease by about \$2.77/MWh in 2008  
5 (decrease from 2007) reflecting operation of the second unit at  
6 PWGS for half a year.

7 Q. Is there any additional information available regarding PTF?

8 A. Yes. Additional information is available on the Web site at  
9 [www.wepowerthefuture.com](http://www.wepowerthefuture.com).

10 TRANSMISSION COSTS

11 Q. Will the Company's participation in ATC improve transmission  
12 access and reliability?

13 A. Yes. The transfer of the Company's transmission facilities to  
14 ATC, together with ATC's participation in the MISO, will  
15 benefit customers by improving reliability through the  
16 institution of a comprehensive, long-term planning process for  
17 making needed transmission enhancements and upgrades on a  
18 regional basis.

19 Q. Is the Company active in reviewing transmission service rate  
20 proceedings by ATC and MISO?

21 A. Yes. The Company is active in reviewing transmission rate  
22 proceedings and where/when appropriate files intervention at  
23 FERC.

24 Q. What is the amount of transmission costs the Company is  
25 proposing to include in its 2006 PSCR plan costs?

26 A. The 2006 PSCR plan includes the 2006 transmission costs for ATC  
27 and MISO of \$152,123,000. Exhibit A-6 (TPL-6) contain the  
28 forecasted ATC and MISO costs for the period 2006 through 2010.

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NOx Reduction Costs

Q. Have you included nitrogen oxide ("NOx") reduction costs in the Company's 2006 PSCR plan?

A. Yes. The Company petitioned for rehearing of the September 16 2002 Order in MPSC Case No. U-12725 to renew its unopposed request to use deferred accounting and escrow treatment for nitrogen oxide reduction costs and to reconcile those costs in annual PSCR reconciliation proceedings. On January 21, 2003, the Commission issued its Order on Rehearing in MPSC Case No. U-12725 granting this request. Consistent with that order, the 2006 PSCR plan includes an estimate of the NOx reduction costs for 2006 amounting to \$30,367,490. See Exhibit A-7 (TPL-7), page 2.

PSCR FACTORS

Q. Have you compared the change in power supply costs from the 2005 PSCR plan?

A. Yes. Exhibit A-7 (TPL-7) shows the power supply costs for both 2005 and 2006 and the difference in cost and MWh. For generation, the increased cost per MWh are due in large part to the increase in projected coal, oil and natural gas prices. For purchased power, the decrease in MWh is due to the PWGS being in-service for a full year and MISO is running the coal units more. The other power supply cost increase is from network transmission. The following table shows the contribution by source of power supply costs:

| <u>Description</u> | <u>PSCR Cost</u>                  |
|--------------------|-----------------------------------|
| 2005 PSCR Factor   | \$ .01253                         |
| Fuel               | <del>\$ .00423</del><br>\$ .00317 |

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|   |                      |                                       |
|---|----------------------|---------------------------------------|
| 1 | Purchased Power      | <del>(\$ .00036)</del><br>(\$ .00070) |
| 2 | Opportunity Sales    | (\$ .00032)                           |
| 3 | Network Transmission | \$ .00011                             |
| 4 | NOx Reduction        | <u>(\$ .00006)</u>                    |
| 5 | Total Change         | <u>\$ .00360</u>                      |
| 6 | 2006 PSCR Factor     | \$ .01613                             |

7 Q. Please describe Exhibit A-11 (TPL-11).

8 A. Page 1 of Exhibit A-11 (TPL-11) shows the Company's annual  
 9 power supply cost recovery factor of 16.13 mills per kWh for  
 10 January through December, 2006. The calculations in the top  
 11 section of page 1 of Exhibit A-11 (TPL-11) derive monthly and  
 12 an annual power supply cost recovery factors for 2006 using a  
 13 base cost of power supply of \$13.79 per MWh at generation level  
 14 for costs. The base cost represents the power supply cost that  
 15 was authorized by the Commission in Case No.U-12725, dated  
 16 September 16, 2002.

17 Page 2 of Exhibit A-11 (TPL-11) details the anticipated power  
 18 supply costs and the net system requirement for the various  
 19 energy sources for each month from January through December,  
 20 2006. The net system requirements section of the page shows  
 21 the anticipated generation mix which will be utilized in  
 22 meeting the system requirements, including fossil, nuclear, and  
 23 hydraulic generation and alternative energy coming primarily  
 24 from Company-owned windmill systems. The net system  
 25 requirement also includes purchased power and external sales.

26 Q. What are the total system power supply costs for 2006?

27 A. The total system power supply costs for 2006 are \$951,219,866.

MPSC

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Thomas P. Lorden

1 Q. Would you please describe the sources of the amounts provided  
2 on Page 2 of Exhibit A-11 (TPL-11)?

3 A. The costs and megawatt-hours for fossil, combustion turbine,  
4 hydraulic generation, purchased power, and external sales are  
5 summarized from Exhibit A-3 (TPL-3).

6 Q. Are there any anticipated adjustments to the costs?

7 A. No.

8 Q. How does the Company propose to apply the proposed power supply  
9 cost recovery factors?

10 A. The Company proposes to apply a uniform PSCR factor of \$.01613  
11 per kWh. The proposed factors by month are shown on Exhibit A-  
12 12 (TPL-12).

13 Q. Are you proposing to modify Rate Sheet No. 15 in any other  
14 manner?

15 A. No.

16 Q. Does this conclude your testimony?

17 A. Yes, it does.

S T A T E    O F    M I C H I G A N  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

|                                               |   |                  |
|-----------------------------------------------|---|------------------|
|                                               | ) |                  |
| In the matter of the application of           | ) |                  |
| WISCONSIN ELECTRIC POWER COMPANY              | ) |                  |
| d/b/a We Energies for approval of a power     | ) |                  |
| supply cost recovery plan and authorization   | ) | Case No. U-14707 |
| of monthly power supply cost recovery factors | ) |                  |
| <u>for the calendar year 2006</u>             | ) |                  |

REBUTTAL TESTIMONY OF THOMAS P. LORDEN

ON BEHALF OF

WISCONSIN ELECTRIC POWER COMPANY

April, 2006

## WISCONSIN ELECTRIC POWER COMPANY

Before the Michigan Public Service Commission

Direct Testimony of Thomas P. Lorden

1 Q. Please state your name and business address.

2 A. Thomas P. Lorden, 231 West Michigan Street, Milwaukee,  
3 Wisconsin 53203.

4 Q. Did you cause direct testimony and exhibits to be pre-filed on  
5 behalf of Wisconsin Electric Power Company ("Wisconsin  
6 Electric" or the "Company") in this case?

7 A. Yes.

8 Q. What is the purpose of your rebuttal testimony in this  
9 proceeding?

10 A. The purpose of my rebuttal testimony is to rebut Nicolas  
11 Phillips, Jr's prefiled direct testimony.

12 Q. Have you reviewed the pre-filed direct testimony of Mr.  
13 Phillips as filed in this proceeding?

14 A. Yes.

15 Q. On page 3 of Mr. Phillips' testimony, he states: "WEPCO's PSCR  
16 Plan takes demand-related capacity-related purchased power and  
17 Network Transmission cost and erroneously transforms them into  
18 per kWh energy costs." Has this issue been addressed in a  
19 previous PSCR case?

20 A. Yes. Mr. Phillips put forth this same argument in the  
21 Company's 2002 PSCR Plan, Case No. U-13107. On page 10 of the  
22 order in that case, dated March 12, 2003, the Commission stated  
23 that the argument is without merit and that by putting forth

1 such an argument, the intervenor proposed to change the ongoing  
2 procedures used to implement the PSCR clause.

3 Q. On page 3 of Mr. Phillips' testimony, he states "The Commission  
4 should insure that Michigan ratepayers are not overcharged for  
5 increased losses due to the overlap between WEPCO's 6% loss  
6 factor and the losses included in MISO's Locational Marginal  
7 Pricing (LMP)." Is there an overlap between WEPCO's 6% loss  
8 factor and the losses included in MISO's LMP?

9 A. No, it is not the Company's intent to overlap losses. Rather  
10 the intent is to ensure that PSCR Plan costs and actual costs  
11 are accounted for on the same basis.

12 The purpose of the 6% loss factor that the Company applies is to  
13 get the generation-level power supply costs per megawatthour to  
14 a customer-level basis for the purpose of calculating the PSCR  
15 factor.

16 Only the incremental cost of marginal losses is included in the  
17 power supply cost plan, as shown on Exhibit A-3 (TPL-3), page 4  
18 under MISO Energy Market Costs. The incremental cost of  
19 marginal losses is projected to be \$7,850,045 which is the  
20 remainder of the projected cost of **MISO - Losses** of \$46,832,347  
21 less the projected cost of **MISO - Loss Distribution** (average  
22 losses) of \$38,982,302.

23 Q. Does this conclude your rebuttal testimony?

24 A. Yes, it does.

1 JUDGE NICKERSON: Any objection to  
2 proposed Exhibits A-1 through A-12?

3 MR. WATERS: I would request that you  
4 defer ruling on the admissibility of those until after  
5 the close of cross-examination.

6 JUDGE NICKERSON: Very well.

7 All right. Cross-examination,  
8 Mr. Odunlami?

9 MR. ODUNLAMI: We don't mind if  
10 Mr. Waters wants to go first.

11 JUDGE NICKERSON: Very well.

12 MR. WATERS: May I proceed?

13 JUDGE NICKERSON: Yes, sir.

14 CROSS-EXAMINATION

15 BY MR. WATERS:

16 Q. Mr. Lorden, you've identified for the record the three  
17 changes that you made this morning to your pre-filed  
18 direct testimony, those being on pages 36, 45 and 46.  
19 In response to some questions from Mr. Bloomberg, you  
20 indicated that you had also made some changes with  
21 regard to Exhibit A-1 and Exhibit A-2, but you did not  
22 describe for the record what those changes were; would  
23 you please identify those changes.

24 A. Sure. Exhibit A-1, the change was made to the line  
25 entitled Municipal Sales and Line Losses and Net

1       Accrual. The reason for the change was that the, in  
2       the original exhibits the Municipal Sales were the  
3       Booked Month Values versus the Billed Month Values.

4   Q.   You've identified the line item of the changes, but you  
5       have not identified the changes themselves; could you  
6       please do that?

7   A.   For Exhibit A-1 under Municipal Sales each one of the  
8       values for year 2006 through 2010 will have changed and  
9       on the revised exhibit; beginning with 2006 for  
10      municipal sales the value is 77,883. 2007, the value  
11      is 43,761. 2008 the value is 40,628. 2009, the value  
12      is 41,386. 2010 the value is 40,965.

13   Q.   Okay. And the change in that line item for 2006 is a  
14      59 percent change, is that correct?

15   A.   Subject to check.

16   Q.   Is that about right?

17   A.   Sure.

18   Q.   Okay. I think yesterday when we spoke with counsel he  
19      indicated, at least to my understanding, one change for  
20      municipal sales, and that was under 2006, so I  
21      understand your testimony today to be the change also  
22      that line items in the years 2007, -8, -9 and -10, is  
23      that correct?

24   A.   That's correct.

25   Q.   My understanding was similarly with regard to the

1        Losses and Net Accrual line, that that would be  
2        changing for '06 but there is no change I guess for all  
3        of those years?

4        A.    That's correct.

5        Q.    Would you please describe the changes that you made to  
6        Exhibit A-2.

7        A.    For Exhibit A-2, page 1 of 2, again the revised exhibit  
8        for Municipal Sales corrected the amounts that were  
9        previously on there. The amounts that were on the  
10       original exhibit as filed reflected the year 2010, not  
11       2006. And again, the Loss and Net Accrual amounts  
12       changed for each one of the months.

13       Q.    I note that even though apparently the original  
14       incorrectly included the year 2010 in that line item,  
15       you have now changed that to 2006, that the total  
16       column didn't change?

17       A.    That is correct.

18       Q.    That seems kind of unusual, at least to me --

19       A.    Not really.

20       Q.    -- is there some reason for that?

21       A.    Because the line Losses and Net Accrual, the net  
22       accrual changes to reflect any change in other sales.

23       Q.    Okay. So the fact that --

24       A.    It's just an offsetting change.

25       Q.    Well, but you had 12 changes for the Municipal Sale

1 line and you have 12 changes for the Loss and Net  
2 Accrual line, and then you had two other changes when  
3 you summed those up, so it's just mere coincidence that  
4 the numbers and the total just happened to be the same?

5 A. No. The net accrual is a fallout of any change. It's  
6 a residual.

7 Q. Okay. Do you have copies of your Exhibits A-11 and A-3  
8 in front of you?

9 A. Yes, I do.

10 Q. Could we look first at Exhibit A-11.

11 A. Okay.

12 Q. Do you have that in front of you?

13 A. Yes, I do.

14 Q. Structurally is it fair to characterize what you've  
15 done in this exhibit is divide WEPCO's Total Power  
16 Supply Costs by WEPCO's Net System Requirements to come  
17 up with your PSCR Factor?

18 A. Yes.

19 Q. And WEPCO's Total Power Supply Costs and Net System  
20 Requirements are identified in detail in Exhibit A-3,  
21 is that correct?

22 A. That's correct.

23 Q. Okay. Can we now turn to Exhibit A-3.

24 A. I did.

25 Q. I'm going to have some general questions and some

1 specific questions with regard to Exhibit A-3, and I  
2 guess I'll just start with the general questions. Is  
3 it fair to characterize Exhibit A-3 as covering the  
4 cost of energy obtained by the company either from its  
5 own generating resources or from power purchases from  
6 others?

7 A. Yes.

8 Q. Page 1 of 2 of Exhibit 3 identifies I believe the cost  
9 of energies produced by each of the companies generated  
10 in there, is that correct?

11 A. Yes.

12 Q. I'm sorry, I meant pages 1 and 2 of Exhibit 3.

13 A. Yes, sir, that's correct.

14 Q. That's how you understood the question?

15 A. Yes.

16 Q. In the middle of page 2, you total the actual  
17 production cost for the projects identified above under  
18 the caption Total Other Production, is that correct?

19 A. Yes, that's true.

20 Q. Now turning to page 3 if you would, please; does that  
21 represent WEPCO's projected actual cost of purchased  
22 power?

23 A. That represents WEPCO's projected cost of purchased  
24 power for 2006.

25 Q. But you're trying to project what you think the actual

- 1           number would be as accurately as you can?
- 2    A.    Using projected loads, yes.
- 3    Q.    And the first category of cost on page 3 are WEPCO's
- 4           traditional power purchase costs for contracts with
- 5           individual suppliers, is that correct? And I think
- 6           those are LS Power, Alliant, Zion and Ameren?
- 7    A.    Yes.
- 8    Q.    And the second category of costs that are identified on
- 9           page 3 are WEPCO's net costs from MISO transactions, is
- 10          that correct?
- 11   A.    Yes, it is.
- 12   Q.    And the net MISO transaction costs were determined by
- 13          netting WEPCO's MISO market purchases against WEPCO's
- 14          MISO market sales, is that correct?
- 15   A.    That is correct.
- 16   Q.    So the amount that ends up being identified as its
- 17          projected actual cost of all transactions in the MISO
- 18          market is the net amount shown under the caption Net
- 19          MISO Transactions?
- 20   A.    Correct.
- 21   Q.    You've specified a dollar amount for both the MISO
- 22          market purchases and the MISO market sales and netted
- 23          those against each other in those two categories, is
- 24          that correct?
- 25   A.    Yes, it is.

1 Q. Were the dollar amounts priced at MISO's locational  
2 marginal price at LMP?

3 A. The dollar amounts were priced at MISO's marginal cost  
4 component of the LMP, yes.

5 Q. Well, I think there are three marginal cost components;  
6 was it one or was it all three?

7 A. It was one, marginal energy cost.

8 Q. Turning to the top of page 4 again, just kind of a big  
9 picture, in the, under the caption Sales, am I correct  
10 that what you have done there is you have netted sales  
11 to PJM and to Edison Sault against the costs that are  
12 identified in the previous two pages?

13 A. Yes.

14 Q. And then the, the next category of costs is just MISO  
15 Energy Market Costs, is that correct?

16 A. That is correct.

17 Q. Okay. And those are the MISO costs other than the  
18 energy component which was contained in the previous  
19 page?

20 A. That is correct.

21 Q. With regard to the Network Transmission line, am I  
22 correct that you included the network transmission  
23 cost? If you look it says Network Transmission  
24 Services, I think you total it up at \$152 million, is  
25 that correct?

- 1 A. That's correct.
- 2 Q. And you did that because you're calculating both the  
3 cost to produce and deliver energy?
- 4 A. Yes.
- 5 Q. In the PS?
- 6 A. Yes.
- 7 Q. Let's go back if we could to Exhibit A-11. I note that  
8 at the very top you specify Total Power Supply Costs of  
9 \$951,219,864, is that correct?
- 10 A. Yes, it is.
- 11 Q. And I assume that's intended to be the same as the  
12 second to last figure on page 4 of 4 in the right-hand  
13 column, which is \$2.00 different but I just want to  
14 confirm that?
- 15 A. Yes, it's supposed to be the same.
- 16 Q. Okay. A-3, if you look at Exhibit A-3, page 4 of 4,  
17 under the MISO Energy Market Costs, that includes  
18 46.8 -- tell me when you get there.
- 19 A. I am.
- 20 Q. Okay. That includes \$46.8 million in MISO transmission  
21 loss charges, correct?
- 22 A. Yes.
- 23 Q. And then you credit or net against that \$38.9 million  
24 in MISO transmission credits, is that correct?
- 25 A. Correct.

1 Q. So the net amount of MISO transmission losses that  
2 is included in WEPCO's Total Power Supply Cost of  
3 \$951 million includes \$7,850,045 for MISO transmission  
4 losses, is that correct?

5 A. Yes.

6 MR. WATERS: Your Honor, I'm going to be  
7 using some other exhibits, including a potential  
8 exhibit which has been numbered LP-25, which would be  
9 subject to a confidentiality agreement if I used it.  
10 I'm going to momentarily withhold that. If I can get  
11 the big picture information that I need without it, I  
12 will not end up offering LP-25. I'm making the point  
13 now so that the record is clear as to the numbering of  
14 these exhibits.

15 JUDGE NICKERSON: All right.

16 MR. BLOOMBERG: Your Honor, I object to  
17 the marking of that exhibit.

18 MR. WATERS: It hasn't been marked, your  
19 Honor. It has only been numbered. I have not given it  
20 to the court reporter to mark, and I don't intend on  
21 doing so until I cross that bridge.

22 MR. BLOOMBERG: Your Honor, I don't have  
23 a problem at this point if he were to present it to the  
24 witness, and I guess we'll take it question by question  
25 after that.

1                   MR. WATERS: Well, actually I think for  
2                   the moment I'm going to skip over that particular  
3                   exhibit and see if I can deal with some other matters  
4                   first.

5                   JUDGE NICKERSON: All right. Off the  
6                   record.

7                   (Discussion off the record.)

8                   JUDGE NICKERSON: On the record. Thank  
9                   you.

10          Q.     (Continuing): You've indicated, Mr. Lorden, that  
11                  WEPCO's total power supply cost already of -- strike  
12                  that.

13                         You've indicated WEPCO's total power  
14                  supply cost \$951 million includes \$7.8 million of MISO  
15                  transmission losses. Am I correct that on your  
16                  Exhibit 11 you then multiply that number, which  
17                  includes, which is included within the total power  
18                  supply cost, by a loss multiplier of 1.06?

19          A.     Yes, that's correct.

20          Q.     And could you take a look at LP-26, please.

21                         MR. WATERS: And for the record this is  
22                  WEPCO's Response To Tilden Mining's Discovery Request  
23                  No. 027, it is labeled TM-WE-027.

24          Q.     (Continuing): And there are three columns on the chart  
25                  that is attached to WEPCO's discovery response, is that

1 correct?

2 A. Yes.

3 Q. And if you look at the PSCR column on the left, you  
4 will see four little blanks for MISO Energy Market and  
5 Point-To-Point Transmission both for Cost for  
6 Generation, is that correct?

7 A. That's correct.

8 Q. Now, that represents the base case, correct?

9 A. Yes, it does.

10 Q. In fact, you have changed what was done there under the  
11 column PSCR Plan Case 2006, you've actually included  
12 certain Transmission Costs, is that correct?

13 A. Yes.

14 Q. And in doing that, in including -- the loss factor  
15 approved by the commission was a composite number;  
16 well, it was a number 1.06, is that correct?

17 A. Yes, it is.

18 Q. And am I also correct that that composite number was  
19 intended to cover both distribution losses and  
20 transmission losses?

21 A. That's correct.

22 Q. So that loss number would have covered the \$7,850,045  
23 of MISO transmission losses, because those were  
24 transmission losses, correct?

25 A. That 1.06 refers to the loss, system losses, both

1 transmission and distribution, that are needed to take  
2 the generation level costs that are shown on this  
3 exhibit and get them to the customer level basis for  
4 which the customer's factor is based.

5 Q. And the commission determined that a loss, and the  
6 commission determined that a composite loss factor of  
7 1.06 covered all of those losses, correct?

8 A. That's correct.

9 Q. And when the commission calculated that 1.06 loss  
10 factor, they applied that factor then, you know, to  
11 your PSCR number, correct? That's a number which is  
12 multiplied against your power supply cost recovery  
13 number? Down at the bottom you're multiplying the loss  
14 factor, 1.06, times your total system costs, correct?  
15 And I'm looking --

16 A. Yes.

17 Q. -- at --

18 A. Yes, that's correct.

19 Q. And you're looking at LP-26?

20 A. Yes.

21 Q. Okay. WEPCO's current PSCR application actually  
22 changes that because now are you not only applying a  
23 loss factor of 1.06 to total system cost, you're  
24 actually including \$7.8 million in the total cost  
25 number; in other words is it fair, is it not, to

1 conclude what you've done is different than what the  
2 commission has previously authorized?

3 A. No, it is not.

4 Q. But you do agree that there are \$7.8 million of costs  
5 included in your total system cost of \$951 million and  
6 that that already includes \$7.8 million that MISO lost,  
7 correct?

8 A. Yes, it does include 7.8 million of MISO losses, yes.

9 Q. And those are net MISO losses as you've --

10 A. Those are the incremental costs.

11 Q. They are incremental transmission losses, correct?

12 A. Yes, that's correct.

13 Q. And they are incremental marginal losses because if you  
14 turn to page 4 of 4, you have netted out the MISO  
15 losses against the -- I'm sorry, page 4 of 4 of  
16 Exhibit A-3 --

17 A. Yes.

18 Q. -- you've netted out the MISO loss distribution against  
19 the MISO losses?

20 A. Correct.

21 Q. And then when you apply the 1.06 loss factor you are  
22 therefore applying it to a number that already includes  
23 a cost for transmission losses?

24 A. That is correct.

25 Q. Turn to Exhibit A-3, page 4 of 4.

1 A. Okay.

2 Q. Looking in the category of MISO Energy Market Costs;  
3 see that there?

4 A. Yes.

5 Q. Okay. That includes MISO, MISO Total Uplift costs of  
6 \$50 million approximately, correct?

7 A. Correct.

8 Q. Do the MISO Total Uplift costs include revenue  
9 sufficiency cost?

10 A. No, they do not.

11 Q. Do you have a copy of your work papers in front of you,  
12 or do you have a copy available to you someplace?

13 MR. BLOOMBERG: Your Honor, if I can  
14 approach the witness?

15 JUDGE NICKERSON: Yes, sir.

16 MR. BLOOMBERG: Thank you.

17 A. Yes, I do.

18 Q. (Continuing): Okay. Can you turn to what is I believe  
19 the second page in your work papers.

20 MR. BLOOMBERG: Go ahead, yeah.

21 Q. (Continuing): Just make sure we're looking at the same  
22 thing. Yeah.

23 A. Yeah --

24 Q. Would you take a minute to review that and then I'd  
25 like to again ask you if the MISO Total Uplift costs

1 include revenue sufficiency guarantee costs?

2 MR. BLOOMBERG: May I ask for a  
3 clarification, because this is a, the nomenclature here  
4 may be confusing. By "uplift cost" are you referring  
5 to revenue sufficiency payments the company makes?

6 MR. WATERS: How much do you want -- the  
7 document that I'm questioning him on is confidential  
8 and I'm trying to --

9 MR. BLOOMBERG: No, I'm just asking for  
10 what you were referring to in your question. When you  
11 say "costs" are you referring to payments that the  
12 company makes?

13 MR. WATERS: Is there --

14 Q. (Continuing): I'm referring to two things, A-3, page 4  
15 of 4, under the caption MISO Energy Market Costs. Why  
16 don't you look at that first and I'm going to trace it  
17 back.

18 A. Okay.

19 Q. That includes MISO Total Uplift Costs, does it not?

20 A. Yes, it does.

21 Q. And those are costs, correct?

22 A. Yes.

23 Q. Okay. And now Exhibit A-3 doesn't tell you what's  
24 included within that category of MISO Total Uplift  
25 Costs, which is the reason that I've asked you to look

1 at page 2 of your work papers, and is there a column  
2 there that says Uplift Costs?

3 A. Yes.

4 Q. And am I correct that that category of Uplift Costs  
5 does include revenue sufficiency guarantee costs?

6 A. In looking at my work paper, yes, uplift costs do  
7 include both day ahead and real-time revenue  
8 sufficiency guarantee uplift costs.

9 (Discussion off the record.)

10 Q. (Continuing): And are there two amounts listed there  
11 under the column Total Cost, one is 1,110,483 and the  
12 second is 7,192,277?

13 A. Yes, those are the amounts shown on my confidential  
14 document.

15 Q. And for the record I cleared with your counsel how I  
16 was going to approach it so we maintain the  
17 confidentiality of the documents.

18 And those amounts are included on  
19 page 4 of 4 of Exhibit A-3 under MISO Total Uplift  
20 Costs, are they not?

21 A. Those MISO charges are the basis for the 50,000,177  
22 shown on page -- A-3, page 4 of 4.

23 Q. But the answer to my question is the, the roughly  
24 \$8 million that I have identified is included with, on  
25 page 4 of 4 of Exhibit A-3 under that line item MISO

1 Total Uplift Costs, correct?

2 A. Yes, they are included in there.

3 Q. Thank you.

4 And has WEPCO included in its PSCR  
5 calculations the revenue sufficiency guarantee payments  
6 that it receives from MISO?

7 A. No, it has not.

8 Q. And am I correct that for the period from April 1st --  
9 I guess I'll back up. So you've included some of the  
10 costs, but you haven't included the offsetting  
11 revenues, correct?

12 A. We've included --

13 Q. You've included costs, correct?

14 A. Some of the uplift costs, yes.

15 Q. But you haven't included any of the offsetting revenue  
16 sufficiency guarantee revenues? You just said that, I  
17 think.

18 A. We have not included the, both the day ahead and  
19 real-time revenue sufficiency guarantee WEPCO payments  
20 associated with additional fuel costs.

21 Q. And what is the net of those amounts? Is it  
22 37,692,266? And I believe that was for the period from  
23 April 1st, 2005, through November 14th of 2005.

24 A. I don't see that amount.

25 Q. Bear with me, I will find the documents and let you

1 take a look.

2 To your recollection did, did MISO  
3 assess about \$13 million in revenue sufficiency charges  
4 against WEPCO and issue \$51.6 million of revenue  
5 sufficiency make whole payments in 2005, is that  
6 accurate, to the best of your recollection? And if you  
7 don't I can go ahead and find the documents here.

8 A. I believe I recall those amounts. I don't recall who  
9 may have responded to a data request that included  
10 those amounts.

11 Q. Okay. I'm going to show you Mr. Schumacher's Discovery  
12 Response, TM-WE-146, and ask you to read that.

13 MR. ODUNLAMI: Your Honor, if counsel  
14 doesn't mind we are having difficulty locating the  
15 documents he's making reference to, so if he can  
16 provide us a copy, because the numbers I can't  
17 differentiate from what we have.

18 (Discussion off the record.)

19 Q. (Continuing): I'd also like to show you for the record  
20 what has been previously marked as Exhibits LP-11,  
21 which is Discovery Response LP-WE-006 which indicates  
22 that the company paid to MISO \$13,950,570 --  
23 \$13,950,575 in revenue sufficiency charges, do you see  
24 that?

25 A. Yes.

1 Q. Okay. And I'm going to show you what will be marked as  
2 Exhibit LP-42 with Mr. Schumacher. It is Discovery  
3 Response LP-WE-007, and it indicates that the company  
4 has received from the MISO \$51,642,841 in revenue  
5 sufficiency make whole payments; do you see that?

6 A. Yes.

7 Q. And is the difference between those two amounts the  
8 \$37.7 million that is referenced in Discovery Response  
9 Tilden Mining-WE-146?

10 A. If you're asking mathematically, yes.

11 Q. Okay. Mathematically if you analyze -- pardon me,  
12 mathematically if you annualized the \$367,692,266  
13 difference between those amounts, would you agree with  
14 me or at least not have a reason to dispute that  
15 annualized that number comes out to \$53,118,422? I  
16 have a calculator if you'd like to perform that.

17 A. I'm sorry, state that again.

18 Q. The annual -- the \$37 million differential that I've  
19 mentioned applied to the period of time from April 1  
20 through November 14th, okay?

21 You have to say yes or no for the  
22 record.

23 A. Yes.

24 Q. If you annualized that number, because that period is  
25 less than a full year, okay, if you annualized that

1           number would you agree that you come up with  
2           \$53,118,422?

3    A.   Subject to check, yes.

4    Q.   Okay.  Am I correct that you haven't included the  
5           revenue -- well, strike that.

6                        You previously testified that you have  
7           not included the revenue sufficiency guarantee payments  
8           in your PSCR calculations, but what I understand from  
9           the company's testimony is that they don't want to do  
10          so in the plan case even though they do want to include  
11          it under the cost but they're committing to reconciling  
12          those numbers in the PSCR reconciliation case, is that  
13          correct?

14   A.   That is not.

15   Q.   So you're not going to reconcile?

16   A.   No, it is my understanding in the plan case we did not  
17          include RSG make whole payments because we did not have  
18          additional fuel costs to offset those RSG make whole  
19          payments.

20   Q.   But you've included revenue sufficiency cost in the  
21          MISO uplift figure?

22   A.   That is correct.

23   Q.   I'd like to, during 2006 -- change topics here -- WEPCO  
24          anticipates making some third-party sales, is that  
25          correct?

1 A. Yes.

2 Q. And WEPCO's third-party sales include two types of  
3 third-party sales, some that are, the company labels,  
4 it identifies as municipal sales, and some that the  
5 company labels or identifies as opportunities, is that  
6 fair?

7 A. Yes, it is.

8 Q. Okay. A -- could you turn to Exhibit A-11.

9 A. Okay.

10 Q. A-11 identifies the company's Net System Requirements  
11 as being 32,785,257 megawatt hours, and that's on  
12 line 2; do you agree with that?

13 A. Yes.

14 Q. Could we, could you turn next to page 2 of 2 on  
15 Exhibit A-2.

16 A. Okay.

17 Q. Now WEPCO's Net System Requirements that I've  
18 previously identified include among other things what  
19 the company calls Michigan Native Energy, correct?

20 A. Yes.

21 Q. And if you look at Exhibit 2, page 2 of 2 -- pardon me,  
22 Exhibit A-2, page 2 of 2, under the column 2006, you  
23 will see that the Michigan Native Energy for the year  
24 2006 includes 49,147 megawatt hours of third-party  
25 sales to Michigan municipalities, is that correct?

1 A. Yes, it is.

2 Q. Am I also correct that WEPCO's net system requirements  
3 of 32,785,257 megawatt hours includes sales to WPPI?

4 A. Yes, it does.

5 Q. Mr. Lorden, could you identify the amounts of the WPPI  
6 sales, or the amount of WEPCO sales to WPPI, in  
7 megawatt hours?

8 MR. WATERS: Your Honor, may I approach?

9 JUDGE NICKERSON: Yes, sir.

10 A. The amounts for WPPI sales is provided in my work  
11 papers, and the monthly amounts as shown on those work  
12 papers is the monthly amount of sales to WPPI. If I  
13 were to add those 12 values up they would amount to  
14 maybe 1.5 million megawatt hours, subject to check.

15 Q. (Continuing): And subject to check if I were to tell  
16 you that it is 1,490,161 megawatt hours, would that  
17 make sense to you?

18 A. Yes. Yes, it would.

19 Q. And that's for 2006, correct?

20 A. That is correct.

21 Q. WEPCO's total power supply cost of \$951,219,864  
22 includes the cost of fuel and purchase power related to  
23 both the third-party sales to the Michigan  
24 municipalities that are previously identified and to  
25 WPPI, does it not?

1 A. Yes, it does.

2 Q. However, WEPCO has not offset its projected 2006 Total  
3 Power Supply Costs with any projected revenues from any  
4 third-party sales to the Michigan municipalities or to  
5 WPPI, has it?

6 A. That is correct.

7 Q. This differs -- strike that.

8 WEPCO's treatment of those sales to the  
9 Michigan municipalities and the WPPI differs from  
10 WEPCO's treatment of opportunity sales, which I think  
11 are reflected on page 4 of 4 of Exhibit A-3, because  
12 there you do net out your opportunity sales for example  
13 to Edison Sault, is that correct?

14 A. That is correct.

15 Q. Can you identify the revenues that WEPCO expects to  
16 receive in 2006 for third-party sales to Michigan  
17 municipalities or to WPPI?

18 A. No.

19 Q. I think one of the exhibits that I've handed you, and  
20 I'll confirm this in just a minute, identifies WEPCO's  
21 average power supply costs for 2006 as \$29.01 per  
22 megawatt hour; do you have a recollection of that? In  
23 fact, I think it's also identified at the bottom of  
24 Exhibit A-3, page 4 of 4.

25 A. That is correct.

1 Q. If you were to add up the sales to the Michigan  
2 municipals, as well as the sales to WPPI, in the  
3 megawatt hours, the total, subject to your confirmation  
4 if you wish, is 1,539,308 megawatt hours for  
5 third-party sales to those two parties, agreed?

6 A. Yes, subject to check.

7 Q. If you multiply that times your average power supply  
8 costs projected for 2006 of \$29.01 per megawatt hour,  
9 subject to check, does it make sense that you would  
10 come up with an amount of, a dollar amount of sales to  
11 Michigan municipals and -- I'm sorry -- you would come  
12 up with the, an approximation of the revenues that  
13 WEPCO expects to receive from the Michigan municipals,  
14 municipalities and WPPI of \$44,655,335?

15 A. If you were to multiply those sales of 1.5 million  
16 megawatt hours times the average power supply cost of  
17 \$29.01, you would come up with revenues associated with  
18 power supply costs from Michigan municipals and WPPI,  
19 not the total revenues, just the, some portion of  
20 revenues associated with power supply costs.

21 Q. And in any event it would just be an estimate subject  
22 to confirmation in the 2006 reconciliation case,  
23 correct? Because in your reconciliation case you will  
24 be able to confirm the dollar value of any revenues  
25 received from the Michigan municipalities and from

1 WPPI, correct?

2 MR. BLOOMBERG: Your Honor, I object to  
3 the question. I think it contains an assumption that  
4 is not supported by the record and is inconsistent with  
5 commission treatment of revenues from these sales.

6 Historically ever since at least 2001  
7 sales to these parties, which are different than the  
8 opportunity sales which are credited here, under the  
9 WEPCO PSCR clause and as the reconciliation says they  
10 have been applied, these third-party revenues are not  
11 included in PSCR reconciliations. And so this  
12 question, this amount would not be a fair estimate to  
13 be corrected in a PSCR reconciliation. Actually, this  
14 whole line of questioning regarding these revenues is  
15 not likely, it's not relevant to this proceeding  
16 because under the clause and planned proceedings as  
17 they have been applied these amounts are not, these  
18 revenue amounts are not included as offsets of power  
19 supply costs.

20 MR. WATERS: Are you done?

21 May I respond?

22 JUDGE NICKERSON: Yes, sir.

23 MR. WATERS: I would cite to your Honor  
24 the commission's decisions, the December 18th, 2003  
25 decision in Case No. 13808; the February 28th, 2005

1 decision in 13917-R; and the June 30th, 2005 decision  
2 in Case No. U-14274. I think counsel has made a leap  
3 of logic concluding what the commission will do here.

4 It is our strong belief that these  
5 revenues should be offset against the company's other  
6 PSCR costs. The commission has clearly done that in  
7 other cases. I am trying to establish the record in  
8 this hearing so that we can make the legal arguments in  
9 a brief so that your Honor and the commission will be  
10 able to address it at that time and, you know, without  
11 the ability to do that you will be asked to decide an  
12 issue in the abstract which makes no sense. I think  
13 you should decide it upon the best possible knowledge  
14 that can be obtained.

15 MR. BLOOMBERG: Your Honor, I don't  
16 think that any of those commission, any commission  
17 orders that he has cited supports his position. Those  
18 orders that I believe he's referring to relate to  
19 Consumers Energy PSCR cases.

20 The issue in that case which were  
21 whether revenues which all conceded were to be applied  
22 to the benefit of customers, they were to be applied to  
23 PSCR customers, unless they were applied to stranded  
24 costs, is a factual situation which is significantly  
25 different than what's present in this case.

1 MR. WATERS: May I -- I apologize.

2 MR. BLOOMBERG: In those cases the  
3 revenues and costs related to those sales were included  
4 in the cost of service determined in Consumers Powers'  
5 base rates. Customers were paying a proportion of  
6 those production costs related to those power supply  
7 sales through their base rates, and they were entitled  
8 to a credit from those sales. It was just a question  
9 of how that credit was to be applied.

10 That situation is significantly  
11 different than what's presented with the company in its  
12 PSCR plan and clause and base rates. In setting the  
13 company's base rates back in the last rate case, which  
14 is MPSC Case No. 12725, there is a cost of service  
15 study done, and Michigan tariff customers and their  
16 rates are based on the cost of service that is assigned  
17 to them. There are other costs that the company incurs  
18 to serve other customers. Those customers include  
19 their largest customer base in Wisconsin. They include  
20 costs related to service to these municipalities and  
21 WPPI. The cost to provide service to the Wisconsin  
22 customers, to WPPI, and to these municipalities are  
23 excluded in determining the cost to provide service to  
24 Michigan customers, including their PSCR cost base in  
25 base rates under the cost of service studies that are

1       done at that time.

2                       Under those base rates and those cost of  
3       service studies, Michigan tariff customers do not pay  
4       for the cost of the power used to make these sales.  
5       Those costs are recovered from those other customers  
6       under other rates. If the revenues from those sales  
7       are captured and credited to PSCR customers, those  
8       revenues are not available to the company to cover its  
9       cost of providing this service to these particular  
10      third-party customers.

11                     That situation was not presented in  
12      either of the Consumers' cases, the 2004 or 2005 PSCR  
13      plan cited by counsel. It's significantly different.  
14      And it is on that basis that these revenues have been  
15      historically not credited to Michigan PSCR customers.  
16      We believe that's the right result. It would involve,  
17      it would require a fundamental adjustment to how the  
18      PSCR clause is applied, and to the company's base rates  
19      to make this type of adjustment, to try to capture  
20      these costs and revenues from other service to this  
21      situation. That's why we believe this is irrelevant to  
22      this proceeding.

23                     I further would like to note that the  
24      commission in its June 30th, 2005 order in 147 -- I'm  
25      sorry -- 14274, Consumers Energy's 2005 PSCR plan, and

1       its February 28th, 2005 order in Consumers Energy's  
2       2004 plan, MPSC Case No. 13917, specifically did not,  
3       declined to determine whether these revenues were to be  
4       offset against PSCR costs or were to be assigned to  
5       stranded costs. Again, these are revenues that are  
6       different than the revenues in this case, but I want to  
7       just note that it's a misrepresentation of those orders  
8       to say that those orders required the revenues in those  
9       cases to be credited against power supply costs for the  
10      plan case. The commission accepted the plan and the  
11      factors as filed with regards to this matter and said  
12      that if they were going to be addressed they were going  
13      to addressed in a reconciliation proceeding.

14                    So for those two reasons; number one, we  
15      think our situation is significantly different than the  
16      other one cited; and also that the orders that counsel  
17      has cited do not support an adjustment in a plan case  
18      in any event. Thank you, your Honor.

19                   MR. WATERS: Your Honor, I think we're  
20      getting fairly far afield. First, this witness has  
21      already conceded, okay, that the costs for the service  
22      and the service are included in this PSCR case. And  
23      all I'm, what he's saying effectively is that we're  
24      including the cost to provide the service to the  
25      municipalities and to WPPI and we're including the

1 megawatt hours in the total system requirements, but we  
2 don't want to include the revenues.

3 Second, unlike Consumers, WEPCO has  
4 never filed a stranded cost recovery case. This is all  
5 argument, legal argument for briefs. This is clearly  
6 relevant inquiry into their PSCR case, and that should  
7 be the limit of the issue that we deal with at this  
8 point.

9 JUDGE NICKERSON: All right. Well, I'm  
10 very familiar with the Michigan order in U-13808,  
11 having spent considerable amount of time with that.  
12 I'd like to take some time to review the commission  
13 order in 13917-R and 14274, so let's take a 20 minute  
14 recess and we'll come back.

15 (Brief recess taken at 10:41 a.m.)

16 - - -

17 (Exhibits LP-26 through LP-37 and  
18 LP-40 through LP-43 marked.)

19 (Proceedings resumed at 11:09.)

20 JUDGE NICKERSON: All right. On the  
21 record.

22 Mr. Waters, please continue, sir.

23 MR. WATERS: Your Honor, I've given the  
24 witness a set of exhibits to look over. I'm hoping  
25 he'll do that and we can kind of abbreviate the cross

1 here with your Honor's permission.

2 JUDGE NICKERSON: All right. And with  
3 regard to the last question you were posing?

4 MR. WATERS: I'm withdrawing that  
5 question.

6 JUDGE NICKERSON: All right.

7 A. Okay. I've read through them.

8 MR. WATERS: May I proceed, your Honor?

9 JUDGE NICKERSON: Yes, sir.

10 MR. WATERS: Again to confirm for the  
11 record the last question is withdrawn.

12 Q. (Continuing): Mr. Lorden, had WEPCO ever filed a  
13 stranded cost discovery proceeding?

14 A. I don't recall. There may have been one of the  
15 responses to a discovery request, but I don't recall a  
16 response.

17 Q. But do you recall if WEPCO ever filed a stranded cost  
18 recovery proceeding?

19 A. No, I don't.

20 Q. I've handed you what has been previously marked  
21 Exhibits LP-26 through LP-37; have you had an  
22 opportunity to review those?

23 A. Yes, I have.

24 Q. Okay. And were those your answers to questions that  
25 were submitted to WEPCO by Tilden and Louisiana

1 Pacific?

2 A. Yes, they are.

3 Q. And are those answers still true and accurate?

4 A. To the best of my ability to answer those questions,  
5 yes, they are.

6 MR. WATERS: For the record I have not  
7 offered and am withdrawing the offer of Exhibit LP-25,  
8 that was the confidential document that we previously  
9 discussed.

10 I would move for the admission of  
11 Exhibits LP-26 through LP-37, and pending a quick check  
12 with co-counsel --

13 JUDGE NICKERSON: Off the record.

14 (Discussion off the record.)

15 JUDGE NICKERSON: On the record.

16 Mr. Waters?

17 MR. WATERS: No further questions, your  
18 Honor.

19 JUDGE NICKERSON: All right. Any  
20 objection to the admission of proposed Exhibits LP-26  
21 through 37?

22 MR. BLOOMBERG: No, your Honor.

23 MR. ODUNLAMI: No, your Honor.

24 JUDGE NICKERSON: All right. They are  
25 admitted.

1 All right. Before we get to the cross  
2 of staff I'd like to indicate that the rebuttal  
3 testimony of Mr. Lorden, which I neglected to address  
4 earlier, are there any objections to binding in the  
5 rebuttal testimony into the record?

6 MR. WATERS: No, your Honor.

7 MR. ODUNLAMI: No, your Honor.

8 JUDGE NICKERSON: All right. It may be  
9 bound into the record.

10 I assume your cross assumed that it had  
11 been bound?

12 MR. WATERS: It did.

13 JUDGE NICKERSON: Thank you. I  
14 apologize.

15 All right. Mr. Odunlami.

16 MR. ODUNLAMI: Yes. Thank you, your  
17 Honor.

18 CROSS-EXAMINATION

19 BY MR. ODUNLAMI:

20 Q. Good morning, Mr. Lorden.

21 A. Morning.

22 Q. Just a few questions this morning.

23 Does the company WEPCO plan to generally  
24 intervene at FERC for MISO as it relates to RSG  
25 payments?

1 A. I don't know if the company has intervened at FERC  
2 specifically for those charges, but it's the company's  
3 position that it does intervene at FERC regarding MISO  
4 charges, yes, it does. I can't say specifically those  
5 charges.

6 Q. Do you guys have any procedure to verify that the  
7 amount requested by MISO for WEPCO to pay RSG cost, how  
8 do you guys verify that?

9 A. I don't know, I personally don't know.

10 Q. Does WEPCO have a revised dollar amount for the  
11 projected RSG payment for 2006?

12 A. As previously stated in our PSCR plan, both day ahead  
13 and real-time, RSG make whole payments are not included  
14 in the plan because the additional fuel costs which  
15 they offset are not included in the plan.

16 Q. And has WEPCO seen any stabilization in the western  
17 coal rail shipment situation?

18 A. I'm going to have to defer to Mr. Schumacher on that  
19 one, on that issue. He'd be more familiar with that  
20 procedure.

21 Q. Do you have your testimony in front of you?

22 A. Yes, I do.

23 Q. Could you please go to page 29.

24 A. Okay.

25 Q. I'm interested in lines, I think it's line 15,

1 question, and line 16 to 24, the answer given in that,  
2 on that page.

3 A. Yes.

4 Q. Is there a change in the volume of the 14.8 million  
5 MMBTU of gas, is there a change in that?

6 A. Again this is based upon a plan for 2006. If you're  
7 asking me to compare that to the first three months of  
8 actual 2006 --

9 Q. Whatever projections has been done since you filed  
10 testimony.

11 A. Generally since we've incurred a lower than normal  
12 first quarter in 2006 we probably have used less gas in  
13 the first quarter of 2006 actual basis.

14 Q. Do you know the number, do you know the number that's  
15 been used in 2006?

16 A. No, not offhand.

17 Q. Do you think the V.A. change to the projected cost of  
18 gas commodity of \$10.87 by MMBTU, do you think there  
19 will be a change of that cost of gas?

20 A. Again I'll defer to Mr. Shumacher on that.

21 Q. Okay. Is there a change to the gas usage estimates at  
22 Neenah, Zion or Elgin plants?

23 A. Again, if I was comparing that to actualized, yes,  
24 there's been a change, and there's probably less usage  
25 at those plants in the first quarter of '06.

- 1 Q. Do you know the number?
- 2 A. No, I do not.
- 3 Q. Is there any possibility of the Point Beach Nuclear  
4 Facility leaving the NMC, do you see that happening in  
5 the foreseeable future?
- 6 A. I don't know. I think the company's position is that  
7 they're looking at all the alternatives associated with  
8 Point Beach Nuclear Power Plant.
- 9 Q. Do you know what steps WEPCO has taken to minimize NOx  
10 emissions at its generating plants?
- 11 A. Offhand I don't. I would defer to Mr. Schumacher.
- 12 Q. Okay. Do you have Exhibit, I think A-8, TLP-8; do you  
13 have that in front of you?
- 14 A. Yes, I do.
- 15 Q. And I'm interested in Supplier D, and I think you  
16 stated in that exhibit that the contract will expire at  
17 the end of 2005?
- 18 A. That's correct.
- 19 Q. Is there a plan to replace those numbers for  
20 February 2006, have you replaced those at all, has  
21 those been replaced?
- 22 A. I'm not aware of what contracts may have been approved  
23 in the past three months.
- 24 Q. Okay.
- 25 A. I don't know.

1 Q. Who should know?

2 A. I don't know if Mr. Schumacher will be aware or not;  
3 otherwise, we could get you the name of our coal buyer.

4 MR. ODUNLAMI: That's it for me, your  
5 Honor. No further questions.

6 JUDGE NICKERSON: All right.  
7 Redirect, Mr. Bloomberg?

8 MR. BLOOMBERG: Yes, your Honor. I  
9 would like to take maybe five minutes --

10 JUDGE NICKERSON: Very well.

11 MR. BLOOMBERG: -- with the witness. I  
12 don't know if you'd rather do that, then start redirect  
13 now, or take a lunch break, do you --

14 JUDGE NICKERSON: Why don't we take a  
15 few minutes off the record and try and wrap him up this  
16 morning.

17 MR. BLOOMBERG: All right. Thank you,  
18 your Honor.

19 JUDGE NICKERSON: Off the record.

20 (Brief recess taken.)

21 JUDGE NICKERSON: All right. On the  
22 record.

23 Redirect, Mr. Bloomberg?

24 MR. BLOOMBERG: Thank you, your Honor.

25

1 REDIRECT EXAMINATION

2 BY MR. BLOOMBERG:

3 Q. Mr. Lorden, you were asked a question regarding what  
4 types of costs were included in the LMP amount paid to  
5 MISO; do you recall that question?

6 A. Yes, I do.

7 Q. And I believe your answer was that those included MISO  
8 energy costs, is that correct?

9 A. Correct.

10 Q. Are there other cost components of a MISO LMP?

11 A. Yes, there are three, and two of those components, the  
12 marginal energy costs and the marginal congestion  
13 costs, were included, not the marginal losses.

14 Q. Okay. You were asked some questions regarding losses  
15 and were referred to what's been marked as or admitted  
16 as Exhibit LP-26; do you have that in front of you?

17 A. Yes, I do.

18 Q. Under the columns marked PSCR Plan 2006 in the middle  
19 of the page there's a cost column and a generation  
20 column and then an average cost per megawatt hour  
21 column; do you see those?

22 A. Yes, I do.

23 Q. Do losses impact both generation levels and costs?

24 A. Yes.

25 Q. So there's a, both a physical and a financial aspect of

1           them?

2       A.    Of losses, correct.

3       Q.    In the cost column as far as the financial impact of  
4           losses, how are losses, the cost related to those,  
5           reflected in the cost column?

6       A.    The cost to serve the customer would include losses for  
7           distribution and also losses for transmission cost.

8       Q.    And are the financial impacts of the losses related to  
9           the distribution system incorporated into the cost in  
10          the cost column?

11      A.    Yes, they are.

12      Q.    How are the losses related to transmission incorporated  
13          in the items in the cost column?

14      A.    Transmission, incremental transmission costs  
15          incurred from MISO are also included in the 2006 PSCR  
16          cost.

17      Q.    Are there other costs related to losses at transmission  
18          level included in the costs in the cost column?

19      A.    Not that I'm aware of.

20      Q.    And the total system cost at the bottom of that column  
21          of approximately \$951 million, that incorporates the  
22          costs financial aspects of losses that you described?

23      A.    Yes, it does.

24      Q.    Does the application of the loss factor towards the  
25          bottom of that exhibit increase those costs to be

1 recovered?

2 A. No, it does not.

3 Q. What is the purpose of that loss factor?

4 A. The purpose of that loss factor is to adjust the cost  
5 per megawatt hour on a generation level basis down to a  
6 cost per megawatt hour on a customer basis.

7 Essentially we're collecting the 951 million over less  
8 megawatt hours.

9 Q. So the, the impact of that, if I may, is the effect of  
10 dividing the 951 million by the proposed PSCR sales?

11 A. No.

12 Q. Oh.

13 A. The impact of that would be dividing the 951 million by  
14 the total system sales at a customer level of  
15 approximately 90-point -- I'm sorry,  
16 30.8 million-megawatt hours.

17 Q. Okay. Thank you.

18 With regards to the development of the  
19 total system costs, that includes cost to serve  
20 customers in Wisconsin?

21 A. Yes, it does.

22 Q. It includes cost to serve municipalities and co-ops?

23 A. Yes, it includes costs to serve all customers.

24 Q. Are the costs related to providing service in Wisconsin  
25 recovered from PSCR customers?

1 A. No, they are not.

2 Q. Are the costs incurred in providing service to  
3 municipalities under FERC rates recovered from PSCR  
4 customers?

5 A. No, they are not.

6 Q. Are the costs incurred in providing service to WPPI  
7 recovered from PSCR customers?

8 A. No, they are not.

9 Q. Are you familiar with how the company's base rates and  
10 base cost of power supply included in base rates have  
11 been historically set by the commission?

12 A. Yes, I am.

13 Q. Does that include a cost of service study?

14 A. That's true, yes.

15 Q. Does that cost of service study separate the cost  
16 related to providing service to customers in Wisconsin  
17 municipalities at FERC tariff rates and WPPI from the  
18 cost used to determine rates for Michigan tariff  
19 customers?

20 A. Yes, it does.

21 MR. BLOOMBERG: I have no further  
22 questions, your Honor. Thank you.

23 JUDGE NICKERSON: All right. Thank you.  
24 Recross, Mr. Waters?

25 MR. WATERS: Could we have one minute,

1 your Honor?

2 JUDGE NICKERSON: Yes, sir.

3 (Discussion off the record.)

4 MR. WATERS: We have a couple, just a  
5 very few questions on recross.

6 JUDGE NICKERSON: Yes, sir.

7 MR. WATERS: With your Honor's  
8 permission, Mr. Marvin would like to ask those  
9 questions and I will not.

10 JUDGE NICKERSON: Mr. Bloomberg, any  
11 objection?

12 MR. BLOOMBERG: Your Honor, in the  
13 interest of expediting things, we'll go ahead with it.

14 JUDGE NICKERSON: All right. Any  
15 objection, Mr. Odunlami?

16 MR. ODUNLAMI: No, your Honor.

17 JUDGE NICKERSON: All right.

18 Mr. Marvin?

19 MR. MARVIN: Thank you, your Honor.

20 RECROSS-EXAMINATION

21 BY MR. MARVIN:

22 Q. Mr. Lorden, I just want to follow up on your last  
23 couple answers. You were talking about Exhibit LP-26  
24 and you made it clear that the cost to serve Wisconsin  
25 municipalities -- excuse me, municipal utilities and --

1 Michigan municipal utilities, were included in the  
2 costs shown in the \$951 million for the PSCR plan  
3 column of that exhibit, correct?

4 A. Yes, sir.

5 Q. And then Mr. Bloomberg asked you whether those costs  
6 that are included in the 951 were then recovered from  
7 Michigan PSCR customers?

8 A. That's correct.

9 Q. And I think I thought I heard your answer was no?

10 A. That is correct.

11 Q. Okay. So there's a portion of the PSCR factors shown  
12 on Exhibit LP-26 that is not actually going to be  
13 charged to the Michigan customers, is that right?

14 A. Again, the purpose of coming up with the total system  
15 power supply cost is to get an average cost across the  
16 entire system, cost per megawatt hour basis, and apply  
17 it to the sales subject to PSCR. So the customers not  
18 under PSCR are paying the average cost of power supply.

19 Q. And the customers under PSCR include Michigan PSCR  
20 customers?

21 A. Yes.

22 Q. And the costs that they're being asked to share in  
23 include the cost to serve Michigan municipal utilities  
24 and WPPI?

25 A. They're being asked to pay the cost of the average

1 power supply cost of the entire system, yes.

2 Q. So the average power supply costs for the entire system  
3 include the cost to serve Michigan municipal utilities  
4 and WPPI?

5 A. Yes, all customers.

6 Q. And so when the Michigan customers pay their PSCR  
7 factor, those costs, or a portion of those costs, are  
8 included in what Michigan PSCR customers would pay,  
9 correct?

10 A. A portion of the cost, the average cost, yes.

11 MR. MARVIN: I have no further  
12 questions. Thank you, your Honor.

13 JUDGE NICKERSON: All right. Thank you,  
14 Mr. Marvin.

15 Mr. Odunlami, any recross, sir?

16 MR. ODUNLAMI: No, your Honor.

17 JUDGE NICKERSON: All right. Witness,  
18 you're excused.

19 THE WITNESS: Thank you, your Honor.

20 (At 11:50 a.m. the witness was excused.)

21 (Exhibit Nos. A-13, A-14 and A-15  
22 marked.)

23 JUDGE NICKERSON: Mr. Bloomberg?

24 MR. BLOOMBERG: Your Honor, at this time  
25 Wisconsin Electric Power Company would like to Paul D.

1 Schumacher to the stand, please.

2 - - -

3 P A U L D. S C H U M A C H E R

4 was called as a witness on behalf of WEPCO

5 and, having been duly sworn to testify the truth,

6 was examined and testified as follows:

7 DIRECT EXAMINATION

8 BY MR. BLOOMBERG:

9 Q. Good morning.

10 A. Morning.

11 Q. Can you please state your name for the record.

12 A. Paul D. Schumacher.

13 Q. By whom are you employed?

14 A. Wisconsin Electric Power Company.

15 Q. Did you cause to be pre-filed in this matter a document  
16 entitled, "The Direct Testimony of Paul D. Schumacher  
17 on Behalf of Wisconsin Electric Power Company,"  
18 consisting of a cover page and 14 numbered pages?

19 A. I did.

20 Q. Do you have a copy of that in front of you?

21 A. I do.

22 Q. Did you also cause to be pre-filed in this matter a  
23 document entitled, "The Rebuttal Testimony of Paul D.  
24 Schumacher on Behalf of Wisconsin Electric Power  
25 Company"?

1 A. Yes.

2 Q. And does that consist of a cover page and six numbered  
3 pages?

4 A. It does.

5 Q. Do you have in front of you what's been marked by the  
6 court reporter as proposed Exhibits A-13, -14 and -15?

7 A. I do.

8 Q. Were those prepared under your direction and  
9 supervision?

10 A. They were.

11 Q. Do you have any revisions or corrections to your direct  
12 testimony?

13 A. No, I do not.

14 Q. Do you have any revisions or corrections to your  
15 rebuttal testimony?

16 A. No.

17 Q. If I were to ask you the questions set forth therein  
18 today would your answers be the same?

19 A. They would be.

20 Q. Are they true and correct to the best of your  
21 knowledge?

22 A. Yes.

23 MR. BLOOMBERG: Your Honor, I move for  
24 binding in of the Direct and Rebuttal Testimony of Paul  
25 D. Schumacher, and the admission of proposed Exhibits

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1 A-13, -14 and -15.

2 JUDGE NICKERSON: I get it. All right.

3 Any objection to binding in the Direct  
4 and Rebuttal Testimony of Mr. Schumacher?

5 MR. WATERS: No, your Honor.

6 MR. ODUNLAMI: No, your Honor.

7 JUDGE NICKERSON: All right. They may  
8 be bound into the record, the Direct and Rebuttal  
9 Testimony.

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STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

|                                                                                                                                                                                                                                                          |                                 |                  |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------|------------------|
| In the matter of the application of <b>WISCONSIN<br/>ELECTRIC POWER COMPANY</b> d/b/a We Energies for<br>approval of a power supply cost recovery plan<br>and authorization of monthly power supply cost<br>recovery factors for the calendar year 2006. | )<br>)<br>)<br>)<br>)<br>)<br>) | Case No. U-14707 |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------|------------------|

DIRECT TESTIMONY OF PAUL D. SCHUMACHER

ON BEHALF OF

WISCONSIN ELECTRIC POWER COMPANY

SEPTEMBER, 2005

WISCONSIN ELECTRIC POWER COMPANY  
Before the Michigan Public Service Commission

Direct Testimony of Paul D. Schumacher

1 Q. Please state your name and business address.

2 A. My name is Paul D. Schumacher and my business address is 333  
3 West Everett Street, Milwaukee, Wisconsin 53201.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Wisconsin Electric Power Company d/b/a We  
6 Energies ("Wisconsin Electric" or the "Company") as Manager -  
7 Planning, in the Commodity Resources area of the Commodity  
8 Business Unit.

9 Q. Please describe your educational background.

10 A. I hold a BS degree in Environmental Science from the  
11 University of Wisconsin - Green Bay, a MS degree in  
12 Environmental Science and a MS degree in Engineering from the  
13 University of Wisconsin-Milwaukee. I am a registered  
14 Professional Engineer in the State of Wisconsin.

15 Q. What have been your employment responsibilities with Wisconsin  
16 Electric?

17 A. I have 31 years experience at Wisconsin Electric in a variety  
18 of areas and responsibilities. These include management of  
19 power plant chemical engineering, corporate environmental  
20 management and most recently as manager of planning. In my  
21 current position, my responsibilities now include strategic

1 and tactical planning and analytical support for power  
2 resource decisions, fuel planning, pricing and related  
3 activities.

4 Q. Have you previously testified before this Commission?

5 A. Yes. I provided testimony before the Michigan Public Service  
6 Commission in 2004 as part of the Company's 2005 PSCR filing.

7 Q. Are you sponsoring any exhibits?

8 A. Yes, I am sponsoring Exhibit A-13 (PDS-1) through Exhibit A-15  
9 (PDS-3). Exhibit A-14 (PDS-2) is provided in redacted form  
10 because it contains detailed confidential cost information  
11 with regard to purchase power contracts. In accordance with  
12 prior Protective Orders, an unredacted version will be made  
13 available to the Commission Staff subject to the appropriate  
14 confidential restrictions.

15 Q. Were these exhibits prepared by you or under your direction  
16 and supervision?

17 A. Yes.

18 Q. What is the purpose of your testimony in this proceeding?

19 A. The purpose of my testimony is to provide information and  
20 exhibits related to the Company's power purchase and sales  
21 contracts in support of the 2006 power supply cost recovery  
22 plan and to provide information related to the projected  
23 impact of the Midwest Independent Transmission System Operator  
24 ("MISO") market on our 2006 power supply costs.

25 Q. Mr. Schumacher, could you please summarize your testimony?

26 A. Yes. My testimony will show that Wisconsin Electric's long-  
27 term purchase contracts for capacity and energy are reasonable

1 and prudent and that their costs should be included in the  
2 2006 PSCR plan costs.

3 Q. Turning first to the long-term purchase power contracts,  
4 please describe in general terms the process employed by  
5 Wisconsin Electric to procure such power.

6 A. The Company considers a power purchase agreement to be long-  
7 term if it has a total duration of 6 months or greater.  
8 Wisconsin Electric makes long-term purchase power commitments  
9 so as to secure a firm supply of power in order to meet  
10 expected customer demands and to provide a long-term hedge for  
11 increasing energy costs. Meeting capacity requirements and  
12 maintaining an adequate planning reserve margin are essential  
13 to satisfy the Company's obligation to provide reliable  
14 service to all of the Company's customers in both Michigan and  
15 Wisconsin. The Company begins the process by assessing its  
16 long-term power supply needs. This includes a review of  
17 projected supply shortfall in future years based on a forecast  
18 of customer demand (net of load management) and projected  
19 supply resources; both owned and purchased, already in place.  
20 Studies are then performed to determine the lowest-cost supply  
21 resource to pursue.

22 Actual procurement of purchase power depends on the type and  
23 duration of the expected agreement and the market conditions  
24 at the time of the selection. For example, the purchase of  
25 power from a new plant to be built in the Company's geographic  
26 area typically requires a more formal Request for Proposal  
27 ("RFP") and a longer-term contract. A shorter term purchase,  
28 one or two years, from existing sources may best be

1 accomplished with a more informal approach since the formal  
2 release of a RFP may actually cause the market price of the  
3 source to rise.

4 Q. You stated that these long-term agreements are required to  
5 meet capacity requirements and maintain an adequate reserve  
6 margin. What is the Company's planning reserve margin, how is  
7 it determined and explain how the purchases meet the need for  
8 capacity for 2006.

9 A. The Company plans for a minimum 18% reserve margin in order to  
10 meet the Public Service Commission of Wisconsin ("PSCW")  
11 requirement for planning reserve margins. In its letter dated  
12 September 24, 1997, the PSCW states that "The Commission  
13 determined that under current circumstances it would be  
14 appropriate for the Wisconsin Utilities to utilize a planning  
15 reserve margin of 18 percent." This minimum planning reserve  
16 margin was confirmed in comments of the PSCW filed with the  
17 Federal Energy Regulatory Commission ("FERC") in Docket No.  
18 RM-01-12-000 on Electricity Market Design and Structure dated  
19 May 2, 2002, and in the PSCW's decision in the Company's 2003  
20 fuel case (Docket No. 6630-UR-111) as filed in February 2003.  
21 My Exhibit A-13 (PDS-1) provides quantitative information with  
22 respect to the determination of the Company's planning reserve  
23 margin for 2006, the need for capacity and the projected peak  
24 loads based on the Company's current load forecast. The  
25 Company, in determining the need for the additional capacity,  
26 compared its demand plus the minimum reserve requirement to  
27 its total power supply resources which include the Company's  
28 generation and any firm power purchase agreements with

1 associated capacity already in place. This Exhibit A-13 (PDS-  
2 1) shows that the capacity agreements included in the PSCR  
3 plan for 2006 are essential in augmenting the Company's own  
4 generation capacity so as to meet the Company's demand  
5 obligations.

6 Q. What factors are considered by Wisconsin Electric when these  
7 power purchase decisions are made?

8 A. There are many factors considered. First, the amount of lead-  
9 time available before the power is needed dictates whether or  
10 not sufficient time exists to consider newly constructing  
11 generating capacity versus existing units. Second, the  
12 location of the supply resource is critical to assuring the  
13 power can be delivered on a firm basis to the Company's  
14 control area, under the MISO Open Access Transmission Tariff,  
15 given current constraints on transmission in the Upper  
16 Midwest. The evaluated cost of purchase power over the term of  
17 the agreement, both the fixed capacity payments and variable  
18 energy payments, are critical factors in selecting power  
19 supply contracts. Other factors include the credit worthiness  
20 of the supplier, diversity of power supply options, expected  
21 reliability of supply, bonus/penalty provisions for  
22 performance; nomination, scheduling or dispatch rights, and  
23 need to achieve certain portfolio standards such as renewable  
24 energy requirements; etc.

25 Q. Turning to a more specific discussion of Wisconsin Electric's  
26 long-term purchase power agreements that are included in 2006  
27 PSCR costs, please describe the changes to the Company's  
28 resource supply portfolio since the time of the 2005 PSCR

1 filing, as amended. For a description of long-term purchase  
2 power agreements which have not changed from the 2005 PSCR  
3 filing, please refer to my pre-filed direct testimony dated  
4 September, 2004 a copy of which is attached to my Exhibit A-14  
5 (PDS-2) My Exhibit A-14 (PDS-2) also lists and summarizes the  
6 demand and energy charges and the transmission costs  
7 associated with each of the long-term power purchase  
8 agreements.

9 A. The changes to the Company's resource supply portfolio are:

10 Marquette Board of Light & Power: This 10-year purchase was  
11 negotiated in the fall of 1995. The 31 MW of capacity was in  
12 place for the period January through June 2005, and as such,  
13 is not part of the company's portfolio for 2006.

14 Q. Does the Company anticipate entering into additional long-term  
15 power purchase agreements for capacity and energy in 2006?

16 A. Not at this time. The Company will request approval at a  
17 later date of any additional long-term power purchases  
18 necessary to meet its demand requirements including reserves.

19 Q. Has the Company entered into other long-term purchase  
20 agreements, which do not have specific capacity payments or  
21 other agreements, which affect power supply costs?

22 A. Yes. The Company has long-term energy agreements for the  
23 purchase of renewable energy, agreements for firm transmission  
24 service, and firm purchase and sale agreements as described  
25 below.

26 Miscellaneous Renewable Energy Contracts: For 2006, Wisconsin  
27 Electric has entered into eighteen (18) renewable energy  
28 agreements with fourteen (14) different suppliers,

1 representing four (4) different sources of renewable energy.  
2 The suppliers are Waste Management, Inc. (land fill gas, three  
3 agreements totaling 25 MW and ending in 2010, and one  
4 agreement for 3.2 MW beginning in 2006 through 2021; Outagamie  
5 County, Wisconsin (land fill gas, one agreement for 2.6MW  
6 ending in 2006); G.A.S.-Access (landfill gas, two agreements  
7 for 5MW beginning in 2006 and ending in 2021); FPL-Badger  
8 Windpower, LLC (wind, one agreement for 25.5MW beginning in  
9 2001 and ending in 2011); Ag Environmental Solutions, LLC  
10 (agricultural waste, one agreement for 0.75MW beginning in  
11 2001 and ending in 2011); Top of Iowa (wind, one agreement for  
12 40MW of renewable credits beginning in 2001 and ending in  
13 2011); Onyx/Glacier Ridge (landfill, one agreement for 0.24MW  
14 of renewable credits beginning in 2005 and ending in 2012);  
15 Quantum Dairy (agriculture waste, one agreement for 0.2MW  
16 beginning in 2005 and ending in 2015); Eden Renewable (wind,  
17 one agreement for 3.3MW beginning in 2006 and ending in 2016);  
18 Addison Wind Energy (wind, one agreement for 1.65MW beginning  
19 in 2006 and ending in 2016); Cedarburg Hydro (hydro, one  
20 agreement for 0.156MW beginning in 2002 and ending in 2007);  
21 Rock River Hydro (hydro, one agreement for 0.1MW beginning in  
22 2002 and ending in 2007); N.E.W. Hydro (hydro, one agreement  
23 for 0.25MW beginning in 2002 and ending in 2007), and Maple  
24 Leaf Duck Farm Inc. (agricultural waste, two year agreement).  
25 The contracts with FPL-Badger Windpower, LLC, Ag Environmental  
26 Solutions, LLC and Maple Leaf Duck Farm have provisions to  
27 extend the term beyond the original contract period. While  
28 these contracts reflect a total of approximately 26 MW of

1 installed capacity, wind resources do not provide firm  
2 dispatchable capacity, yielding only 7MW which can be relied  
3 upon as firm capacity. Each of the renewable energy sources  
4 that is in operation, with the exception of the three hydro  
5 facilities, has been certified by the PSCW as being renewable  
6 energy and meeting the requirements of Acts 204 and 9. The  
7 energy costs associated with these purchases for 2006 are  
8 shown in Exhibit A-14 (PDS-2). The energy (MWh) and cost of  
9 these contracts are reflected in Mr. Lorden's exhibits for the  
10 2006 forecast.

11 Transmission Service. The Company has access to 580 MW of  
12 long-term point-to-point transmission service from PJM through  
13 2010 as the result of ComEd joining PJM. This transmission  
14 service facilitates access to the Zion and Elgin facilities as  
15 capacity resources. The cost of the transmission service for  
16 2006 is projected based on various tariffs either approved by  
17 or under consideration by the FERC and is shown on Exhibit A-  
18 14 (PDS-2).

19 Long-term Sales Contracts. The Company has a sales agreement  
20 dated June 27, 1996, with the Edison Sault Electric Company  
21 for 20 MW of capacity and energy through 2007. The Company  
22 also has a joint operating agreement to supply the balance of  
23 Edison Sault's requirements, (approximately 46 MW) until  
24 terminated by one of the parties upon 12-month notice.

25 Q. In your opinion, was Wisconsin Electric reasonable and prudent  
26 in entering each of the long-term agreements you just  
27 described?

1 A. Yes. Each was selected with the best information available  
2 and under the market conditions at the time. Prices, terms,  
3 and conditions vary since these agreements were entered into  
4 at different times and in order to meet different requirements  
5 as part of a portfolio of low-cost supply options.

6 Q. Switching now from long-term purchases to short-term purchases  
7 and sales, please describe how these energy transactions are  
8 conducted under the new MISO marketplace, and the role these  
9 transactions play in Wisconsin Electric's overall cost of power  
10 supply.

11 A. Under the new MISO market place, the Company is required to  
12 offer all available generation into both Day-Ahead and Real-  
13 Time markets, less generation held back for reserves, and bid  
14 virtually all its load into the Day-ahead market. Actual  
15 deviations in Day-Ahead schedules are priced at Real-Time  
16 prices. Under this approach, MISO pays (\$/MWh) each of the  
17 Company's generators for the energy supplied at the hourly  
18 Locational Marginal Price ("LMP") at the facility, and in  
19 turn, invoices the Company for the energy purchased hourly  
20 (\$/MWh) at each load node. The net of hourly generation  
21 revenue and load cost represents short-term energy purchases  
22 and sales under the MISO marketplace. The Company's projection  
23 for the net of generation revenue and load cost for 2006 is  
24 \$63.69/MWh, and is provided on Exhibit A-15 (PDS-3)

25 Q. Exhibit A-14 (PDS-2) indicates that for 2005 the average  
26 annual cost of total purchases is \$102.75/MWh while average  
27 annual sales to MISO are \$46.95/MWh (Exhibit A-15 (PDS-3)). Is  
28 it reasonable that the annual average cost per MWh for

1 purchases is projected to be higher than the average amount  
2 per MWh for sales?

3 A. Yes. On an average cost basis, total purchase power costs are  
4 more than sales to MISO. That is to be expected since the  
5 Company's purchase power has a large capacity charge component  
6 while sales to MISO do not. The Company does not buy power  
7 for the sole purpose of re-selling it to the MISO market.

8 Q. Are any of the power purchases you described required to  
9 specifically serve Michigan customers?

10 A. No. Wisconsin Electric operates on a total system basis which  
11 works to the advantage of Michigan customers. Most hours of  
12 the year, Wisconsin Electric is importing power into the Upper  
13 Peninsula in order to reduce overall system costs. If  
14 Wisconsin Electric were to split its operations along state  
15 lines, rates for Michigan customers, overall, would increase.

16 Q. Please briefly describe any other impacts on fuel costs  
17 related to the MISO Day 2 energy marketplace in the 2006 PSCR  
18 plan.

19 A. In addition to energy transactions (sales & purchases) with  
20 MISO, other MISO costs associated with operating in the energy  
21 market are included in this 2006 PSCR filing (Exhibit A-15  
22 (PDS-3)). A description of each of these cost elements, along  
23 with a projection for 2006 costs is provided below:

24 • CONGESTION

25 MISO includes in the hourly LMP a calculated charge for  
26 congestion on the transmission system associated with each

1 Commercial Pricing node ("CP node"). This charge is set forth  
2 on daily settlement statements from MISO and is invoiced  
3 weekly by MISO. Based on five months of operation within the  
4 MISO market, the Company has projected 2006 congestion costs  
5 at about \$52.2M. MISO employs a system utilizing Financial  
6 Transmission Rights ("FTR") to help hedge congestion costs.  
7 FTRs are allocated to market participants by MISO through a  
8 four tier nomination and allocation process based on  
9 transmission and resource supply entitlements. The value of  
10 FTRs is based on Day-Ahead congestion, with MISO reporting FTR  
11 revenue to FTR holders on daily settlement statements. The FTR  
12 allocations for 2006 are established in separate annual and  
13 monthly allocations, with the first allocation period running  
14 from January 1 through May 31, 2006. FTR allocations for this  
15 phase are completed, with the Company receiving about 89% of  
16 the FTR it nominated. The second FTR allocation phase for 2006  
17 will extend from June 1 through December 31, 2006. FTR  
18 nominations and allocations for this phase will occur during  
19 the first quarter, 2006. Based on FTR experience to-date, the  
20 Company projects total 2006 FTR value at about \$50.8M. The  
21 Company nets the FTR revenue with congestion costs to arrive  
22 at a net cost for transmission congestion. The projected net  
23 2006 congestion is estimated at about \$1.6M. This estimate  
24 will be refined as actual Day Ahead congestion and the results  
25 of the second phase allocation are known. We will update our  
26 modeling input data and assumptions as new information is  
27 identified to project both congestion costs and FTR revenues  
28 as accurately as possible.

## LOSSES

MISO calculates marginal transmission losses based on an analysis of transmission system loss contributions to each CP node, and projects the cost of marginal transmission costs on daily settlement statements. In an effort to provide a transition from the historic use of average transmission system losses to the new energy market and the corresponding use of marginal losses, MISO calculates a re-distribution and indicates that amount on the daily settlement statements. This "rebate" is currently under study by MISO, and will be phased out after five years of market operation. The Company projects the net cost of transmission losses for 2006 at about \$7.8M.

## UPLIFT/Revenue Sufficiency Guarantee

MISO collects money from market participants to perform the following:

- Day Ahead Revenue Sufficiency Guarantee Distribution Amount is collected from market participants and used by MISO to fund the Day Ahead Make Whole payments to generators.
- The Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount charges are collected from market participants that have load in real time that deviates from their Day Ahead nominations, who offer generation into the Day-Ahead market which is scheduled by MISO but is unable to perform at Day Ahead scheduled amount or must run at higher than Day Ahead scheduled amount and generators that do not

1 follow MISO dispatch instructions. MISO uses this charge to  
2 fund the Real-Time Make Whole payments to generators.

3 • The Real Time Revenue Neutrality Uplift charges provide a  
4 balancing mechanism for MISO including the costs of Real Time  
5 Make Whole payments not fully recovered through the First  
6 Pass Distribution Amount.

7 • Net Inadvertent Distribution charges and payments are  
8 collected from or paid to control areas to balance energy  
9 flows between MISO and external control areas.

10 • Real Time Miscellaneous Account is a mechanism that allows  
11 MISO to collect costs or distribute revenues which are not  
12 covered by other categories.

13 Based on 2005 experience, the Company projects the net impact  
14 of the above charge and revenue categories on the 2006 fuel  
15 budget of about \$50.2M.

#### 16 ADMINISTRATIVE

17 MISO charges market participants various administrative  
18 charges to administer the Day Ahead Market, Real Time Market  
19 and Financial Transmission Rights Market. Based on 2005  
20 experience, the Company projects the net impact of the above  
21 charges on the 2006 fuel budget of about \$7M.

#### 22 MAKE WHOLE PAYMENTS

23 MISO may dispatch various units, usually gas-fired peaking  
24 units, out of economic merit order for system reliability

1 purposes. MISO will pay the generator its costs to operate to  
2 make the generator whole for costs that are not met by the LMP  
3 revenues received. The Company nets this revenue against fuel  
4 and other costs to provide this non-economic operation. Since  
5 the Company's production cost models are unable to project  
6 this reliability-driven operation, for purposes of this PSCR  
7 filing, we have assumed that make whole payments will  
8 completely cover the cost of this operation, with no net  
9 revenue or cost projected for 2006.

10 Q. Please describe the potential impacts of reduced PRB coal  
11 deliveries at some of the Company's facilities.

12 A. The Union Pacific (UP) Railroad experienced problems in 2005  
13 with delivery of PRB coal to plants across the US due to track-  
14 related problems in Wyoming. The UP is in the process of  
15 repairing the tracks, and expects to be completed later in  
16 2005. During this period of reduced deliveries, the Company has  
17 executed a program of coal conservation at its Pleasant  
18 Prairie, Oak Creek and Edgewater Unit 5 facilities to match  
19 coal burn with deliveries. This coal conservation program has  
20 increased fuel costs during 2005 as lower-cost coal generation  
21 is replaced with energy purchases from MISO and operation of  
22 higher-cost facilities. While the Company expects the UP to  
23 deliver the full amount of PRB coal to its facilities during  
24 2006, it may be necessary to implement coal conservation during  
25 2006 to reestablish coal inventory levels left below target at  
26 the end of 2005 and/or in the event the UP reduces coal  
27 deliveries in 2006.



STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

|                                                                                                                                                                                                                                                  |                                 |                  |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------|------------------|
| In the matter of the application of Wisconsin<br>Electric Power Company d/b/a We Energies for<br>approval of a power supply cost recovery plan<br>and authorization of monthly power supply cost<br>recovery factors for the calendar year 2006. | )<br>)<br>)<br>)<br>)<br>)<br>) | Case No. U-14707 |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------|------------------|

REBUTTAL TESTIMONY OF PAUL D. SCHUMACHER

ON BEHALF OF

WISCONSIN ELECTRIC POWER COMPANY

APRIL, 2006

## 1 WISCONSIN ELECTRIC POWER COMPANY

## 2 Before the Michigan Public Service Commission

## 3 Rebuttal Testimony of Paul D. Schumacher

4 Q. Have you previously provided testimony in this docket?

5 A. Yes. I provided direct testimony in this PSCR proceeding on  
6 September 30, 2005.

7 Q. Have you previously testified before this Commission?

8 A. No. I have previously testified before the Wisconsin Public  
9 Service Commission on various fuel cost related issues.10 Q. What is the purpose of your rebuttal testimony in this  
11 proceeding?12 A. The purpose of my rebuttal testimony is to rebut various issues  
13 raised in pre-filed direct testimony of Mr. Nicholas Phillips,  
14 Jr. (on behalf of Louisiana-Pacific Corporation and Tilden  
15 Mining Company, L.C.) submitted in this case.16 Q. Mr. Schumacher, could you please summarize your rebuttal  
17 testimony?18 A. Yes. I will be addressing the following points raised in Mr.  
19 Phillips' direct testimony: (1) that WEPCo continues to  
20 purchase significant amounts of expensive purchased capacity  
21 and energy from gas-fired facilities (Phillips' testimony, page  
22 2), (2) that MISO revenue sufficiency payments should be a  
23 credit to the PSCR (Phillips' Testimony, page 3, (3) that the  
24 volatility in fuel costs and MISO costs somehow drive a need  
25 for a reduced PSCR factor for WEPCo (Phillips' Testimony, page  
26 3, and (4) that the increased network transmission costs  
27 incorporated into the PSCR are not a least-cost option for

1 providing service to Michigan customers (Phillip's testimony,  
2 page 5).

3 Q. Does Mr. Phillips' ascertainment that WEPCO continues to purchase  
4 significant amounts of expensive purchased capacity and energy  
5 from gas-fired facilities support any adjustment to the  
6 Company's PSCR Plan or proposed factors?

7 A. No. As discussed in my direct testimony, WEPCO utilizes a  
8 capacity planning process that considers many factors in  
9 acquiring supply resources necessary to meet customer demands,  
10 along with an 18% reserve margin. The evaluated cost of  
11 purchase power over the term of the agreement, both the fixed  
12 capacity payments and variable energy payments, are critical  
13 factors in selecting power supply contracts. Exhibit A- (PDS-  
14 2) from my September 30, 2005 pre-filed direct testimony lists  
15 and summarizes the demand and energy charges associated with  
16 each of the long-term power purchase agreements. Purchases  
17 pursuant to each of these power purchase agreements have been  
18 approved in prior PSCR cases. Each of these supply options was  
19 selected with the best information available and under the  
20 market conditions at the time. Prices, terms, and conditions  
21 vary since these agreements were entered into at different  
22 times and in order to meet different requirements as part of a  
23 portfolio of low-cost capacity and energy supply options. The  
24 Company acted reasonably and prudently in obtaining power  
25 supply from its power supply sources.

26 Q. Please describe how the Company's facilities and facilities  
27 under contract to the Company are dispatched under the MISO  
28 energy market.

1 A. In accordance with MISO market rules, the Company offers  
2 virtually all of its generation into the MISO day-ahead energy  
3 market and bids its load into the same market. MISO performs  
4 security-constrained economic dispatch of all the generators  
5 across the MISO footprint based on the generator offers it  
6 receives to meet the projected customer load. As such, MISO  
7 will dispatch gas-fired facilities only after dispatch of  
8 lower-cost generators. In this way, the cost to serve the  
9 customers across the entire MISO footprint is minimized.  
10 Accordingly, Wisconsin Electric seeks to keep its power supply  
11 costs to a minimum through effective operation within the MISO  
12 energy market. Mr. Phillips' observation does not support any  
13 change in the Company's PSCR plan or proposed factors.

14 Q. Turning now to MISO costs and revenue sufficiency credits, how  
15 did Wisconsin Electric project 2006 MISO costs?

16 A. Wisconsin Electric used the only methods available to it to  
17 project MISO 2006 costs. The Company used the September, 2005  
18 PROMOD model output for projecting MISO energy related costs.  
19 The Company adjusted this output by making various adjustments  
20 based upon some April through August, 2005 actual MISO costs.  
21 Based on experience with the MISO market to date, these  
22 techniques for projecting MISO costs remain appropriate for  
23 PSCR plan purposes. The 2006 PSCR reconciliation will address  
24 any variances between projected and actual MISO costs and other  
25 energy related costs.

26 Q. Please describe the reasons behind MISO revenue sufficiency  
27 payments, whether these payments were projected in the 2006

1 PSCR factors, and the disposition of such actual payments  
2 within the 2006 PSCR process.

3 A. MISO dispatches the majority of generators in economic order,  
4 with additional generators dispatched as part of the MISO  
5 Reliability Assessment Commitment ("RAC") process to maintain  
6 reliable operation of the transmission system. These RAC-  
7 committed generators often have operating costs higher than the  
8 MISO hourly LMP levels. Accordingly, MISO provides a "make-  
9 whole" revenue sufficiency payment to these generators to cover  
10 their costs to operate.

11 The Company used the security constrained economic dispatch  
12 model "PROMOD" to project some of its 2006 PSCR costs. This  
13 model does not project unit commitment and operation as set  
14 forth by MISO under the RAC process. Accordingly, the costs of  
15 RAC operations were not included in the 2006 PSCR plan and  
16 factors. During 2006, several of the Wisconsin Electric  
17 generating units are occasionally selected by MISO to operate  
18 under the RAC process. MISO, consistent with its tariff,  
19 provides Wisconsin Electric revenue sufficiency payments to  
20 make the Company whole for such operation. These payments are  
21 used to cover actual operating costs incurred by the Company  
22 for this out-of-economic order operation, and as such, are  
23 included in the Company's monthly PSCR Reconciliation reports  
24 and will be included in the PSCR Reconciliation filing as a  
25 credit under actual fuel costs experienced by the Company  
26 during 2006. Since costs related to RAC operations are not  
27 included in the PSCR plan costs or Factors, revenues or credits  
28 related to RAC operations should also not be included in the

1 PSCR Plan and Factors. To include such credits, without  
2 including the corresponding costs, would under-recover costs  
3 incurred.

4 Q. Is it appropriate to modify the 2006 PSCR factor to somehow  
5 account for volatility in fuel and MISO costs that were  
6 unforeseen at the time of the 2006 PSCR filing?

7 A. No it is not. The key assumptions incorporated into the 2006  
8 PSCR factor included projections of natural gas and coal costs  
9 for 2006, as well as projections for those MISO costs included  
10 in the cost of power supply.

11 Turning first to natural gas, Wisconsin Electric used a  
12 September 7, 2005 NYMEX based projection for 2006 natural gas  
13 costs, as adjusted for hedge volumes as of that date. At that  
14 time, projected gas costs ranged from about \$12/dth for the  
15 first several months of 2006 to about \$9/dth for the remainder  
16 of the year. Current NYMEX projections project the remainder  
17 of 2006 gas prices slightly less than the September 7, 2005  
18 forecast. However, much uncertainty remains around natural gas  
19 costs for the remainder of 2006.

20 In addition, 2006 coal costs projected in September, 2005 are  
21 less than actual coal costs being incurred during 2006,  
22 especially at Presque Isle Units 1-6. These variances in gas  
23 and coal cost projections will tend to balance out through  
24 2006, and will be incorporated on an overall net basis in the  
25 2006 reconciliation.

26 Q. Has the Michigan Public Service Commission previously  
27 addressed the statement made by Mr. Phillips regarding network  
28 transmission costs?

1 A. Yes, several times. In the Company's most recent Michigan  
2 base rate case, MPSC Case No U-12725, the Commission in its  
3 September 16, 2002 Opinion and Order, page 8, found the  
4 decision to transfer transmission assets to American  
5 Transmission Company, LLC to be reasonable and prudent. In  
6 its January 22, 2004 decision, pages 7-8, in Case No. U-13556,  
7 the Commission addressed essentially this same issue, stating:

8 The Commission agrees with the finding of the ALJ to permit  
9 the inclusion of projected transmission costs over those  
10 included in the utility's PSCR base in this case. The  
11 Commission has already found, in Case No. U-12725, the  
12 transfer of transmission assets to ATC to be prudent and,  
13 absent a claim of error or newly discovered evidence or  
14 circumstances, will not revisit its decision. Additionally,  
15 ATC's rates are subject to FERC jurisdiction and, although the  
16 Commission may chose to intervene in a FERC proceeding  
17 addressing ATC's rates, once the rates are established they  
18 cannot be second-guessed by this Commission. Wisconsin  
19 Electric has testified that it has no alternative source for  
20 these transmission services and the Commission has previously  
21 approved the inclusion of transmission costs in the PSCR  
22 factor. Consequently, the Commission finds that the projected  
23 incremental costs for transmission services in Wisconsin  
24 Electric's 2003 PSCR plan case are reasonable.

25  
26 Consistent with the Commission's rulings above, Mr. Phillips's  
27 comments regarding transmission costs do not support any  
28 revision to the Company's PSCR plan or proposed PSCR Factors.

29  
30 Q. Does this conclude your rebuttal testimony?

31 A. Yes, it does.

1                   MR. WATERS: For what it's worth, I have  
2           no objection to the admission of Mr. Schumacher's three  
3           exhibits.

4                   JUDGE NICKERSON: Any objection?

5                   MR. ODUNLAMI: No, your Honor.

6                   JUDGE NICKERSON: All right. Proposed  
7           Exhibits A-13, A-14 and A-15 are admitted. All right.  
8                   Cross-examination, Mr. Waters?

9                   MR. WATERS: Yes, your Honor.

10                   CROSS-EXAMINATION

11   BY MR. WATERS:

12   Q.   Mr. Schumacher, I would like to hand you what has been  
13           marked as Exhibits LP-40, LP-41, LP-42, and LP-43, and  
14           ask you to take a minute and review those.

15                   MR. WATERS: And your Honor, for the  
16           record, we had previously prepared two exhibits, LP-38  
17           and LP-39, which we will not be offering.

18   Q.   (Continuing): Have you had an opportunity to review  
19           those three exhibits?

20   A.   I have.

21   Q.   And were those answers prepared by you?

22   A.   They were.

23   Q.   Okay. And are those answers still true and accurate as  
24           you sit here today?

25   A.   To the best of my knowledge.

1                   MR. WATERS: Your Honor, I would move  
2                   the admission of Exhibits LP-40 through LP-43, and in  
3                   lieu of engaging in cross-examination on those issues I  
4                   would just ask that they be admitted, and if they are  
5                   then I would have no cross-examination of this witness.

6                   JUDGE NICKERSON: All right.

7                   Any objection to the admission of  
8                   proposed Exhibits LP-40, -41, -42 and -43?

9                   MR. BLOOMBERG: Your Honor, we have no  
10                  objection provided that we are reserving and not  
11                  waiving a right to ask him redirect on the information  
12                  included in these exhibits.

13                  JUDGE NICKERSON: Mr. Waters, is there  
14                  any concerns or objections?

15                  MR. WATERS: Your Honor, bear with me  
16                  one moment.

17                  (Discussion off the record.)

18                  MR. WATERS: Back on the record.

19                  I'm in somewhat of a quandary because  
20                  when these Interrogatories, you know, were expounded,  
21                  WEPCO had a full and fair opportunity, you know, to say  
22                  whatever it wanted to. And I'm taking their answer as  
23                  it is. Apparently what they're now saying is they want  
24                  the opportunity, you know, to say even more, and to  
25                  supplement the record and presumably to supplement

1 testimony.

2                   These are admissions, you know, that are  
3 binding against the company in the form in which they  
4 currently exist. And I don't intend on undertaking any  
5 cross-examination with regard to these exhibits. So  
6 given the fact that, you know, redirect is supposed to  
7 be limited to the scope of cross, and there isn't going  
8 to be any cross, it seems inappropriate to me to say,  
9 okay, yeah, I agree to that, because I'm going to open  
10 the record up to let them, I guess, apparently ask  
11 whatever they want, and at the time that they filled  
12 these answers out they were obligated to provide full  
13 and fair answers, which presumably they did.

14                   You know, so before I can agree one way  
15 or the other I guess I probably need a response or a  
16 ruling from your Honor with regard to that issue.

17                   JUDGE NICKERSON: All right. Very well.

18                   Anything from staff?

19                   MR. ODUNLAMI: No, your Honor.

20                   JUDGE NICKERSON: All right. Would you  
21 like to respond, Mr. Bloomberg?

22                   MR. BLOOMBERG: Yes, thank you, your  
23 Honor. Our obligation is to respond to discovery. We  
24 are to respond to the questions asked. Whether we want  
25 to put in additional information, there certainly is a

1 lot of information that may be relevant that's not  
2 within the actual answer to the question that's asked.  
3 And we, these responses were provided either back in  
4 January or December as I see them. Things may have  
5 changed. There may be explanations that may be helpful  
6 to your Honor.

7 When we responded to these questions  
8 this was not a, necessarily drafted as the thought that  
9 this is, this can go in without any opportunity to  
10 redress any other facts or circumstances that may be  
11 relevant or material to this.

12 We are willing to stipulate this as a  
13 way to expedite this in lieu of him asking these  
14 questions. If he asks these questions to the witness  
15 we would have an opportunity to redirect. We are not  
16 looking to expand the scope of redirect beyond  
17 traditional bounds.

18 JUDGE NICKERSON: All right. Thank you.  
19 What I'm going to do is I'm going to hold the request  
20 under advisement. I'm going to allow Mr. Bloomberg an  
21 opportunity to review these particular exhibits and  
22 then to consult with Mr. Waters regarding anything you  
23 think needs to be done with regard to them, and then we  
24 can pick it up tomorrow.

25 MR. BLOOMBERG: Your Honor, I think we

1 can get that done in 15 minutes.

2 MR. WATERS: I think we can too.

3 JUDGE NICKERSON: All righty then.

4 Well, why don't we do that then.

5 Off the record.

6 (Discussion off the record.)

7 JUDGE NICKERSON: On the record.

8 Mr. Waters?

9 MR. WATERS: I'll let Mr. Bloomberg  
10 speak.

11 MR. BLOOMBERG: Your Honor, after  
12 discussion with counsel we stipulate to the admission  
13 of proposed Exhibits LP-40 through 43 without  
14 reservation.

15 JUDGE NICKERSON: All right. Any  
16 objection from staff?

17 MR. ODUNLAMI: No, your Honor.

18 JUDGE NICKERSON: Very well. Proposed  
19 Exhibits LP-40 through 43 are admitted.

20 MR. WATERS: Thank you, your Honor.

21 MR. BLOOMBERG: Thank you, your Honor.

22 JUDGE NICKERSON: All right.

23 Cross, Mr. Odunlami?

24 MR. ODUNLAMI: Yes, your Honor.

25

1 CROSS-EXAMINATION

2 BY MR. ODUNLAMI:

3 Q. Good afternoon, Mr. Schumacher.

4 A. Good afternoon.

5 Q. Just a couple of questions.

6 Does WEPCO have an updated estimate of  
7 2006 net congestion costs?

8 A. No, we don't. We're monitoring each month carefully  
9 but we have not updated our 2006 projection.

10 Q. Have you set any divisions based on your monitoring as  
11 to the projected congestion cost of 2006?

12 A. Not of much substance.

13 Q. How are the FTR credits used or allocated system-wide  
14 to mitigate congestion?

15 A. Well, of course the MISO has FTR allocation periods and  
16 each of the market participants, there's a four-tier  
17 process whereby the market participants can identify  
18 those FTR's which it feels are important to its  
19 operation.

20 Two periods to date, the first period  
21 started of course April 1st and went through I believe  
22 the end of summer of '05; the second period started in  
23 September and is going into '06; the third period, as  
24 we speak we're in the final throes of the nomination  
25 process, and I understand that these, the third phase

1 of these FTR allocations will be in full effect shortly  
2 within several weeks.

3 Q. Could you describe how WEPCO allocates the FTR's it  
4 receives from MISO to its customers?

5 A. The FTR, let me see if I can restate the question;  
6 you've asked how we allocate the FTR revenues that are  
7 received from MISO --

8 Q. Yeah.

9 A. -- for FTR'S?

10 Q. Yes.

11 A. Okay. I have to calibrate. We do it differently in  
12 the two jurisdictions. In Michigan, my understanding  
13 is that the FTR revenues are put directly into the  
14 monthly fuel expense as a credit so that the customers  
15 reap the benefit of the FTR'S as they, as the benefit  
16 is realized on a monthly basis.

17 Q. Do you know whether WEPCO has sufficient NOx credits  
18 for 2006?

19 A. Yes, WEPCO is compliant with all applicable NOx  
20 limitations as of the last date of my review which was  
21 several weeks ago. Moreover the projection of NOx  
22 emissions for the rest of 2006 shows compliant  
23 operation.

24 Q. If there, if there is a change in your operation that  
25 will offset your projection for NOx credits for 2006,

1           how would you allocate that change, make it go up?

2   A.   If the question is does a change of operation --

3   Q.   Assuming --

4   A.   Assuming a change of operation --

5   Q.   Yes.

6   A.   -- how will our NOx position change?

7   Q.   Yes.

8   A.   Okay. The latest projection of NOx emissions that I've  
9       reviewed several weeks ago showed that even with  
10      increased coal plant utilization that WEPCO was  
11      compliant with applicable NOx emission limitations.

12                   MR. ODUNLAMI: That's all the questions  
13   I have, your Honor.

14                   JUDGE NICKERSON: Thank you,  
15   Mr. Odunlami.

16                   Redirect, Mr. Bloomberg?

17                   MR. BLOOMBERG: No, your Honor.

18                   JUDGE NICKERSON: All right. Well --

19                   MR. MARVIN: Your Honor, before we close  
20   could we just have a brief minute to confer?

21                   JUDGE NICKERSON: Yes, sir.

22                   Off the record.

23                   (Discussion off the record.)

24                   JUDGE NICKERSON: All right. On the  
25   record.

1                   Is there anything else before we adjourn  
2           for tomorrow?

3                   MR. BLOOMBERG: Yes, your Honor. I  
4           would just like to note for the record that there was  
5           subpoenas issued for Mr. Aronson and Ms. Simms, and my  
6           understanding is based on the evidence and  
7           cross-examination today that intervenors are releasing  
8           them from the obligation to appear further at this  
9           hearing.

10                  JUDGE NICKERSON: All right.

11                  MR. BLOOMBERG: I'd just like the record  
12           to reflect that.

13                  MR. WATERS: That's correct, your Honor.

14                  JUDGE NICKERSON: Very well.

15                  MR. MARVIN: Your Honor, thank you for  
16           the opportunity to have that brief recess.

17                  After conferring with my co-counsel  
18           today, we've reached the conclusion that we do not  
19           think it's necessary to call Mr. Phillips. His  
20           pre-filed direct testimony we earlier submitted so we  
21           will be withdrawing that and not asking it not be bound  
22           into the record, and therefore there's no need for  
23           hearing tomorrow.

24                  JUDGE NICKERSON: Any objections?

25                  MR. BLOOMBERG: No objection, your

1 Honor.

2 MR. ODUNLAMI: No, not from staff.

3 JUDGE NICKERSON: All right. Then we're  
4 finished here. We basically are closing the record,  
5 all right, just so everybody understands.

6 All right. Is there anything else for  
7 the record then?

8 (No response.)

9 JUDGE NICKERSON: All right. The  
10 record's closed. Thank you very much.

11 (At 12:34 p.m., the hearing was concluded.)

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I, Erin Stilman (CSR-3588), do hereby

certify that I reported in stenotype the proceedings had in

the above-entitled matter, being Case No. U-14707, before

Daniel E. Nickerson, Jr., J.D., Administrative Law Judge, at

the Michigan Public Service Commission, 6545 Mercantile Way,

Lansing, Michigan, on Wednesday, April 26, 2006; and do

further certify that the foregoing transcript, consisting of

145 pages, (Pages 34-178), is a true and correct transcript

of my stenotype notes.

Erin  
Stilman

Digitally signed by Erin Stilman  
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Dated: May 8, 2006