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August 30, 2000

BEFORE THE  
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Electric Power Company for Approval of  
Plan to Improve Reliability Through Infrastructure and Incentives  
and Request for Rate Increase for Test Year 2000

6630-UR-111

**FINAL DECISION**

This is the final decision concerning the application of Wisconsin Electric Power Company (WEPCO or Applicant) for authority to increase electric and natural gas rates in 2000 and electric rates in 2001.

Final overall rate changes are authorized consisting of a \$36,538,000 annual rate increase for Wisconsin retail electric operations, a 2.5 percent increase, and an \$8,000,000 annual rate increase for natural gas operations, a 2.1 percent increase. These rate increases are to be applied to the base rates established in the Commission's order in docket 6630-UR-110, dated April 30, 1998. An additional rate increase of \$27,521,000 is authorized for Wisconsin retail electric operations to be effective January 1, 2001, a 1.8 percent increase over the final electric rates authorized for the 2000 test year. No rate changes are authorized for the city of Milwaukee steam service area or the Milwaukee County Grounds (Wauwatosa) steam service area. Rates are based on a 12.20 percent return on common equity and will be in effect until superceded by an order establishing new rates. A refund is required for the amount of natural gas revenues collected from the interim rates that were authorized in this docket, because the revenues from interim rates exceed the amount that would have been collected during that period under final

rates authorized in this order. In addition, revenues associated with electric reliability and safety construction are subject to refund as described in the Opinion section of this order.

### **Introduction**

On July 6, 1999, WEPCO submitted financial data for the 2000 test year indicating a revenue deficiency in the test year, but requesting no change in rates. On September 17, 1999, WEPCO submitted another filing requesting a two-step rate increase for its electric and natural gas operations and proposing to incorporate certain performance-based measures and incentives. The application involved no change in rates for the company's steam operations, but WEPCO did request a \$46,000,000 (3.1 percent) increase for electric operations and an \$8,000,000 (2.0 percent) increase for natural gas operations to be effective January 1, 2000. For the second step, WEPCO requested an additional \$29,000,000 (2.0 percent) for electric operations to be effective January 1, 2001.

On December 15, 1999, the Commission held a prehearing conference to determine the issues to be addressed in this docket and to establish a schedule for the hearing. At the prehearing conference, WEPCO indicated its intention to request interim rate relief. On December 27, 1999, the company filed its "Motion of Wisconsin Electric Power Company for Interim Rate Order." The motion requested an interim rate increase, subject to refund, of an annual amount of \$46,000,000 for WEPCO's Wisconsin retail electric operations and \$8,000,000 for its natural gas operations.

On January 13, 2000, the Commission issued its Notice of Hearings, which established the hearing schedule for WEPCO's request for interim rate relief as well as the hearing schedule to address WEPCO's request for final rates in this proceeding. In that notice, the Commission

determined that the scope of the interim hearing would be limited to the following issues: (1) the merits of authorizing interim rate increases for electric and natural gas operations subject to refund upon a final determination of revenue requirements; (2) the appropriate level, if any, of interim rate increases for electric and natural gas operations; and (3) how such interim rate increases should be applied to the various rate classes for electric and natural gas operations.

Pursuant to due notice, a hearing was held on February 9, 2000, to address the above issues. On April 11, 2000, the Commission issued an order authorizing an interim rate increase of \$25,199,000 annually for Wisconsin retail electric operations, a 1.7 percent increase, and an interim rate increase of \$11,608,000 annually for natural gas operations, a 3.1 percent increase. The Commission authorized the interim rate increases to be subject to refund, in the event that final rates authorized in this docket are lower than the interim rates.

Pursuant to due notice, a hearing to determine final rates in this proceeding was held on April 25-26, 2000. The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Other persons who appeared are listed in the Commission's files.

### **Findings of Fact**

1. Presently authorized rates for WEPCO's electric utility service will produce Wisconsin retail electric operating revenue of \$1,527,582,000 for the test year ending December 31, 2000, which is inadequate. Presently authorized rates for WEPCO's natural gas utility service will produce Wisconsin retail natural gas operating revenue of \$381,511,000 for the test year ending December 31, 2000, which is inadequate. Presently authorized rates for electric and natural gas service are unreasonable because they produce inadequate electric and natural gas revenues.

2. It is reasonable to require WEPCO to refund any gas revenue it collected, during the period in which interim rates authorized in this docket were in effect, that exceed the revenue that would have been collected under final rates authorized in this order.

3. It is reasonable to increase Wisconsin retail electric rates by \$36,538,000 for the 2000 test year.

4. It is reasonable to further increase WEPCO's Wisconsin retail electric rates by \$27,521,000 effective January 1, 2001, to allow the company to recover incremental costs associated with its electric reliability and safety construction expenditures and costs associated with nitrogen oxide remediation in 2001.

5. It is reasonable to authorize a natural gas rate increase of \$8,000,000, which is the rate increase requested by WEPCO in its application.

6. It is reasonable to authorize no change in rates for WEPCO's city of Milwaukee and Wauwatosa steam operations.

7. For the electric utility, the estimated rate of return on average net investment rate base at current rates subject to the Commission's jurisdiction for the test year is 9.79 percent, which is inadequate.

8. A reasonable increase in operating revenue requirement for the test year to produce a 10.52 percent return on WEPCO's average net investment rate base for Wisconsin retail electric operations is \$36,538,000.

9. A reasonable increase in operating revenue requirement for Wisconsin retail electric operations in 2001 to allow WEPCO to recover incremental costs associated with its electric reliability and safety construction expenditures and costs associated with nitrogen oxide remediation in 2001 is \$27,521,000.

10. A reasonable increase in operating revenue requirement for the test year to produce a reasonable return on WEPCO's average net investment rate base for Wisconsin natural gas operations is \$8,000,000.

11. It is reasonable to continue fully allocating the cost associated with serving in-state, long-term wholesale load to the wholesale jurisdiction by applying the criteria set forth in Wis. Admin. Code ch. PSC 117.

12. It is reasonable to allow no recovery of costs associated with WEPCO's incentive payroll plans and instead allow recovery of a "true-up" amount equivalent to the portion of employees' base wage increases that were initially given up in exchange for the incentive, adjusted to reflect the growth in the number of employees covered by the plan and also to reflect an annual percentage increase in base wages of 3.5 percent for employees participating in the plan.

13. It is reasonable to change the fuel rules monitoring ranges to the following: plus or minus 10 percent monthly; cumulative ranges of plus or minus 10 percent the first month, plus or minus 6 percent the second month, and plus or minus 3 percent for the remaining months of the year; and plus or minus 3 percent for the annual range.

14. The Commission finds the resulting test year fuel cost of \$388,786,825 is reasonable for the purpose of setting just and reasonable rates and reflects the cost of generation, purchased energy, wheeling, and capacity less the revenue from opportunity sales of energy and capacity. The test year fuel cost divided by the test year estimate of net native energy requirements of 30,475,574 MWh results in an average net fuel cost per kWh of \$0.01276. The test year fuel cost is an average of the monthly fuel estimates contained in Appendix D.

15. Amortizing sulfur dioxide (SO<sub>2</sub>) emission allowance revenues of \$1,721,515 and SO<sub>2</sub> expenses of \$1,150,000 annually is reasonable on a total company basis.

16. It is reasonable to require WEPCO to record additional one-time demand-side management (DSM) accruals in 2000 of \$2,858,920 for electric operations and \$328,993 for natural gas operations as well as the associated income taxes to correct the escrow balances. These accruals are not included in the test year revenue requirements. They shall be recorded in addition to the DSM accruals that are included in the test year revenue requirements for Wisconsin retail electric operations and Wisconsin natural gas operations.

17. It is reasonable for WEPCO to amortize the estimated December 31, 1999, DSM escrow under-spent balance of \$5,100,554 for electric operations and the over-spent balance of \$2,827,217 for natural gas operations over a four-year period, beginning with the effective date of this order. The test year revenue requirements include DSM accrual amounts of \$12,853,228 for electric operations (\$14,128,367 of authorized expenditures less \$1,275,139 of amortized underspending) and \$5,601,022 for natural gas operations (\$4,894,218 of authorized expenditures plus \$706,804 of amortized overspending).

18. It is reasonable for WEPCO to amortize the remaining deferred DSM expenditures over a four-year period, resulting in an annual amortization expense of \$5,628,000 for electric operations.

19. A Wisconsin retail electric revenue requirement that includes decommissioning annuities of \$10,995,200 for the qualified annuity and \$4,080,325 for the non-qualified annuity is reasonable.

20. A reasonable expected inflation rate for the test year is 3.10 percent.

21. It is reasonable to apply the expected test year inflation rate of 3.10 percent to the amount of non-payroll operations and maintenance (O&M) expenses of \$265 million identified by WEPCO as the “Total O&M Expenses Related to Inflation” for purposes of determining the final revenue requirement in this proceeding.

22. It is reasonable for WEPCO to accrue allowance for funds used during construction (AFUDC) on 100 percent of its average test year construction work in progress (CWIP) associated with construction expenditures for nitrogen oxide (NO<sub>x</sub>) remediation in 2000 and 2001.

23. It is reasonable for the Commission’s authorized revenue increases for Wisconsin retail electric operations to include \$3,689,000 and \$13,715,000 in 2000 and 2001, respectively, to allow the company to recover its costs in those two years associated with NO<sub>x</sub> remediation.

24. It is reasonable for WEPCO to establish an escrow mechanism for all revenue requirement components, including income taxes, associated with its NO<sub>x</sub> remediation expenditures.

25. It is reasonable for WEPCO to earn a current return, calculated at the adjusted weighted cost of capital rate of 10.18 percent, on 100 percent of average test year CWIP and average 2001 CWIP associated with electric reliability and safety construction expenditures.

26. It is reasonable for WEPCO’s 2001 second step electric rate increase to include \$13,806,000 for the company’s incremental cost associated with reliability and safety construction expenditures, which includes a current return on 100 percent of the associated average CWIP balance in 2001.

27. It is reasonable to make the revenue requirement components associated with WEPCO’s reliability and safety construction expenditures subject to refund. The need for a

refund shall be evaluated at the end of the 2000-2001 biennial period by comparing the actual level of construction expenditures for electric reliability and safety for the 2000-2001 biennial period in total to the forecasted level for the two years.

28. It is reasonable to continue the practice of removing nonutility investments that are not related to the provision of utility service from WEPCO's average common stock equity to arrive at utility common stock equity for purposes of determining the regulatory capital structure and test year revenue requirement.

29. It is reasonable to continue the practice of treating property held for future use as a nonutility investment that is related to the provision of utility service, because WEPCO did not agree to accept conditions that would be necessary to impose if the Commission were to allow the company to earn a return on such investment.

30. It is reasonable that 50 percent of average test year CWIP, excluding CWIP associated with NOx remediation and electric reliability and safety construction expenditures, earn a current return and that WEPCO accrue AFUDC on the remaining 50 percent at the adjusted weighted cost of capital of 10.18 percent.

31. It is reasonable to require WEPCO to submit quarterly reports for the 2000-2001 biennial period showing its actual electric reliability and safety construction expenditures compared with the forecasted level as described in the Opinion section of this order.

32. It is reasonable to require WEPCO to submit a report to the Commission showing its forecasted electric construction expenditures associated with reliability and safety by project for 2001.

33. The test year level of \$444,288 for Manufactured Gas Plant (MGP) amortization expense is reasonable.

34. WEPCO's evaluation plan filed in this rate case for its Natural Gas Vehicle Program is accepted.

35. It is reasonable to require WEPCO to conduct an evaluation of the effectiveness of its Natural Gas Vehicle Program, as described in its approved evaluation plan. This plan requires WEPCO to submit the evaluation results from its historical program activity (1997-99) within 90 days of the date of this order. It requires WEPCO to submit the evaluation results from its future program activity (2000-01) no later than April 30, 2002.

36. WEPCO's proposed budget for its Natural Gas Vehicle Program of \$160,000 is reasonable for the 2000 test year.

37. The capital structure for the test year consisting of 53.45 percent common equity, 0.86 percent preferred stock, 42.61 percent long-term debt and 3.08 percent short-term debt is reasonable for purposes of this proceeding.

38. A long-term range of 48.50 percent to 53.50 percent for WEPCO's common equity ratio is reasonable and provides adequate financial flexibility.

39. A just and reasonable short-term debt interest rate is 6.80 percent for the test year.

40. A just and reasonable interest rate for variable rate bonds is 4.80 percent for the test year.

41. A 12.20 percent return on utility common stock equity is just and reasonable for WEPCO in this proceeding.

42. A weighted average composite cost of capital of 9.77 percent is just and reasonable for WEPCO in this proceeding.

43. It is not in the public interest for WEPCO to pay additional dividends above the amount forecasted in this proceeding if the payment of the additional dividends causes the

average annual rate-making utility common equity ratio to fall below the test year reasonable level of 53.45 percent.

44. It is reasonable to allow WEPCO to pay a special dividend in excess of the forecasted dividends at the end of the year only if the additional payment does not reduce the average annual rate-making common equity ratio below 53.45 percent.

45. It is reasonable to require WEPCO to submit a ten-year financial forecast in its next rate proceeding before this Commission.

46. It is reasonable to approve two-step rates for electric service for the test year to achieve the customer class changes in revenue shown in Appendix B.

47. It is reasonable to continue to use cost-of-service studies based on the average of twelve coincident monthly peaks.

48. It is appropriate to consider cost-of-service studies that use the Minimum System Method.

49. It is reasonable to continue the practice of reviewing a range of cost-of-service studies for purposes of rendering a decision on revenue allocation.

50. It is reasonable for the Commission to rely on all natural gas cost-of-service studies as a guide to setting rates.

51. It is not reasonable for WEPCO to implement its proposed Contractual Swing Quantity (CSQ) balancing proposal for natural gas service at this time. It is reasonable that WEPCO use the traditional approach for balancing, which relies solely on volumetric charges for that service.

52. It is reasonable that WEPCO use the same balancing tiers for cashout and for balancing for natural gas service . Those tiers are: tier (1) 0 to 10 percent; tier (2) 10 to

25 percent; and tier (3) greater than 25 percent. It is reasonable that WEPCO submit a non-CSQ balancing proposal consistent with the new ranges.

53. On natural gas constraint days, it is not reasonable for WEPCO to charge both balancing charges and unauthorized use penalties for imbalances in the same direction as the constraint. For such imbalances on constraint days, only unauthorized use penalties should apply.

54. It is reasonable that WEPCO be allowed to call natural gas system-wide constraints only when physical system integrity is threatened. If economic or pricing issues are encountered with particular transporters or marketers, WEPCO should use selective constraints to address those problems.

55. It is reasonable for WEPCO to continue to use its daily cashout process based on weighted average cost of gas (WACOG) pricing. WEPCO should continue to examine market-based cashout pricing options for the future.

56. It is reasonable that WEPCO should, no later than November 1, 2000, implement a cashout pricing system for natural gas service that reflects a mix of firm and interruptible customers on its system. The mix should be developed based on recent historical records of firm and interruptible loads. It is reasonable that approval of cashout pricing be delegated to the Administrator of the Natural Gas Division.

57. It is reasonable for WEPCO to continue to cashout customers of natural gas service by rate class to reflect the different effective rates that apply to each class.

58. It is reasonable that WEPCO work with marketers, transportation customers, and other interested parties, as well as with the Commission staff, to develop a workable

super-pooling tariff for natural gas service. A workgroup should be formed to develop such a proposal that would be implemented on April 1, 2001, at the latest.

59. Without prejudice as to the merits of deferred accounting for the natural gas super-pooling implementation and operation costs, it is not reasonable at this time to grant WEPCO the right to use such accounting.

60. It is reasonable that WEPCO use the ten natural gas operating zones approved in docket 6630-UR-110.

61. It is reasonable that WEPCO submit its study of the feasibility of offering an in-kind program for gas lost and unaccounted for to Commission staff. It is reasonable that WEPCO continue to use the cash payment method for gas lost and unaccounted for until the Commission determines whether an in-kind option is reasonable.

62. It is reasonable that the maximum credit for distribution capacity in the With or Without Gas Supply Interruption Crediting Service be set at each class's total effective volumetric margin rate.

63. It is reasonable that WEPCO reduce its natural gas nominations deadline lead times to at most 1.5 hours before the initial nomination is due to the pipeline and to at most 1.0 hours before each intra-day nomination is due to the pipeline.

64. It is not reasonable to order WEPCO to implement a specific non-telemetered natural gas transportation program at this time. The Commission will review the company's recent filing on this matter before deciding how to proceed.

65. It is reasonable for WEPCO to continue with its existing notification deadlines for customers wishing to move from natural gas sales to transportation service. WEPCO should continue to work with customers to shorten these deadlines when possible.

66. It is not reasonable to adjust WEPCO's natural gas interruptible sales service pricing at this time.

67. It is reasonable for WEPCO to establish two new rate classes for large-volume natural gas customers. It is also reasonable that the rates for these classes reflect the higher load factors of the customers within the classes.

### **Conclusions of Law**

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code ch. PSC 116 to enter an order authorizing WEPCO to place in effect the rates and rules for electric and gas utility service set forth in Appendices B and C, and the fuel treatment set forth in Appendix D, subject to the conditions specified in this order.

### **Opinion**

#### **Applicant and Its Business**

WEPCO is a public utility as defined in s. 196.01, Stats., operating as an electric, natural gas, and steam utility. WEPCO is engaged in the generation, transmission, distribution, and sale of electric energy in service areas in southeast, east central, and northern Wisconsin and in the Upper Peninsula of Michigan. The service area includes metropolitan Milwaukee. The rates applicable to sales of electric energy at wholesale to municipal utilities for resale are not subject to the jurisdiction of this Commission but are regulated by the Federal Energy Regulatory Commission (FERC) and are not affected by these proceedings. The rates applicable to sales of

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electric energy to Michigan customers are also not subject to the jurisdiction of this Commission, and are not affected by this proceeding.

WEPCO is engaged in the purchase, distribution, and sale of natural gas to retail customers in the southeastern and east central portions of Wisconsin, including Calumet, Dodge, Jefferson, Kenosha, Milwaukee, Outagamie, Racine, Walworth, Waukesha, and Winnebago Counties. WEPCO also operates as a steam heating utility in certain areas of Milwaukee and Wauwatosa.

On January 1, 1987, WEPCO reorganized under s. 196.795, Stats., as authorized by the Commission's order in docket 9402-YO-100, dated May 28, 1986. The reorganization changed WEPCO and its former subsidiary, Wisconsin Natural Gas Company, to separate subsidiaries of a parent holding company, Wisconsin Energy Corporation. The steam utility remained within WEPCO. On January 1, 1996, Wisconsin Natural Gas Company merged into WEPCO.

On March 15, 2000, the Commission issued an order in dockets 9401-YO-100/9402-YO-101 authorizing Wisconsin Energy Corporation to acquire 100 percent of the outstanding common stock of WICOR, Inc., the parent holding company of Wisconsin Gas Company.

### **Income Statement**

The applicant, intervenors, and Commission staff presented testimony and exhibits concerning the estimated cost of electric, natural gas, and steam operations for the 2000 test year and opportunity was afforded all parties to cross-examine the witnesses. Rates in this proceeding are based on a 2000 test year and are expected to remain in effect through 2001 for the company's natural gas operations. The Commission finds it reasonable to authorize an initial rate increase at this time for Wisconsin retail electric service and an additional electric rate

increase effective January 1, 2001, as discussed below. A discussion of several significant issues pertaining to the income statement follows:

**Fully Allocating Costs vs. Opportunity Sales Treatment for In-State Wholesale Sales**

1997 Wisconsin Act 204 created Wis. Stat. § 196.03(5m), which required the Commission to promulgate rules establishing requirements and procedures for the assignment of costs and the treatment of revenues to customers outside this state that a public utility does not have a duty to serve when setting rates for retail electric service. In January 2000, the Commission completed a rule-making process to establish rules for costs and revenues related to out-of-state sales (Wis. Admin. Code ch. PSC 117). This rule became effective on April 1, 2000. Wis. Admin. Code § PSC 117.02 states that the Commission may also apply this chapter to sales to in-state customers that the utility does not have a duty to serve. During the rule-making process, WEPCO and the other investor-owned utilities in Wisconsin provided testimony stating that in-state sales should be treated the same as out-of-state sales.

In this proceeding, WEPCO requested opportunity sales treatment for its in-state, long-term wholesale sales. Under the rule, if a selling utility wants to receive opportunity sales treatment for a wholesale contract longer than three years, the selling utility is required to provide evidence showing that the wholesale sale is being made out of excess capacity and that the excess capacity could be reasonably expected to exist for the entire term of the wholesale sales contract. The Commission finds that WEPCO did not provide such evidence in this proceeding.

In addition, WEPCO provided no evidence in this proceeding to support changing the treatment of long-term wholesale sales from the treatment contemplated in Wis. Admin. Code

ch. PSC 117. Thus, it is reasonable to continue the practice of fully allocating the costs associated with WEPCO's long-term, in-state wholesale sales to the wholesale jurisdiction.

### **Incentive Payroll**

WEPCO's filed payroll estimate for the 2000 test year included \$12.4 million for its Short-Term Incentive Pay Plan (STPP), introduced in 1992, and its Variable Incentive Pay Plan (VIPP), which began in 1995. The STPP initially covered only the officers of WEPCO. Currently, it covers approximately 150 employees in middle management and above. When WEPCO introduced its VIPP, which covers all of the company's non-union employees, it reduced the base wage increases for the first few years of the plan in exchange for the VIPP incentive.

In every rate case since the inception of these plans, the Commission has disallowed recovery of the associated costs. The Commission has included, however, an amount equivalent to the portion of the employees' base wage increases that were initially given up in exchange for the VIPP incentive. This "true-up" amount, included in the level of payroll recovered in rates, has been increased in each successive rate proceeding to reflect the growth in the number of employees covered by the VIPP plan, and has also been increased to reflect an annual percentage increase in base wages of 3.5 percent for employees participating in the VIPP plan.

The Commission's order in docket 6630-UR-110 (dated April 30, 1998) stated, "WEPCO has the burden of proof to establish that the ratepayer benefits of the incentive plans outweigh the costs of the plans." The record in this proceeding is inadequate to make a determination regarding whether the company's payroll incentive plans provide ratepayer benefits which outweigh the costs of the plans. It therefore remains reasonable to include a "true-up" amount of \$6.7 million in the authorized test year revenue requirement. For the future, the Commission

suggests that applicant consider working with Commission staff to develop a plan, consistent with the standards in Wis. Admin. Code ch. PSC 113, that would provide sufficient ratepayer benefits to justify the costs of the plans.

### **Monitoring of Fuel Costs**

The Commission finds that the reasonable test year fuel cost is \$388,786,825, reflecting the cost of generation, purchased energy, wheeling, and capacity less the revenue from opportunity sales of energy and capacity. The test year fuel cost divided by the test year estimate of net native energy requirements of 30,475,574 MWh results in an average net fuel cost per kWh of \$0.01276. The test year fuel cost is an average of the monthly fuel estimates for 2000 as shown in Appendix D.

Under Wis. Admin. Code § PSC 116.04, the Commission must establish monthly and annual ranges for monitoring the test year fuel forecasts. The Commission finds the following variance ranges are reasonable for monitoring the applicant's fuel costs: (1) for the annual range, plus or minus 3 percent; (2) for the monthly range, plus or minus 10 percent; and (3) for the cumulative range, plus or minus 10 percent for the first month of the test year, plus or minus 6 percent for the second month of the test year, and plus or minus 3 percent for the remaining months of the test year. The method of applying those ranges, established in prior Commission decisions for WEPCO, may continue to be used and applied, using the data in Appendix D for monitoring these ranges.

### **Correction of Past DSM Escrow Accruals**

The objective of escrow accounting in a regulatory setting is to ensure that a utility recovers in rates no more and no less than what it spends on a given activity. The Commission

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finds that WEPCO's DSM expense accruals for 1997 and 1998 were not consistent with the amounts authorized in the Commission's rate orders for those periods.

In WEPCO's last rate proceeding, docket 6630-UR-110, the final rate increase did not become effective for the 1998 test year until May 1 of that year. The Commission authorized an interim rate increase in that proceeding based on a percentage of the company's requested rate increase. The order authorizing interim rates included no approval to change previously authorized DSM accruals. Since the Commission did not authorize new DSM accrual amounts in the interim order in docket 6630-UR-110, WEPCO should have continued to record the amounts authorized in its previous rate order in docket 6630-UR-109.

Because the company recorded DSM expense accruals that were different than the authorized amounts in the first four months of 1998, its DSM escrow balances were misstated. To correct WEPCO's DSM balances, it is reasonable to order WEPCO to record additional DSM accruals in 2000 on a one-time basis of \$2,858,920 for electric operations and \$328,993 for natural gas operations, along with the associated income taxes. These one-time accruals are not included in the authorized revenue requirements for the 2000 test year because they were already recovered by the company in 1998. These one-time accruals are to be recorded in 2000 only, in addition to the authorized DSM expense accruals for electric and natural gas operations.

#### **Authorized DSM Expense Accruals**

The authorized DSM expense accruals for electric and natural gas operations recoverable in the test year are \$12,853,228 for electric operations (\$14,128,367 of authorized expenditures less \$1,275,139 for amortization of DSM underspending) and \$5,601,022 for natural gas operations (\$4,894,218 of authorized expenditures plus \$706,804 for amortization of DSM overspending). The amortization of the estimated under- and over-spent DSM escrow balances

for electric and natural gas operations, respectively, includes the correction to the balances discussed above. The amortization amounts represent a four-year amortization of the estimated under- or over-spent escrow balances as of December 31, 1999. It is reasonable to require that these annual DSM accruals continue to be recorded until they are superseded by a Commission order authorizing new DSM accrual amounts.

### **Depreciation and Decommissioning**

WEPCO's filed revenue requirement estimates were based on approved depreciation rates and decommissioning annuity levels. The Commission finds that it is reasonable to calculate a test year revenue requirement using Wisconsin retail decommissioning annuities of \$10,995,200 for the qualified annuity and \$4,080,325 for the non-qualified annuity.

### **Inflation**

In every major rate case, the applicant utility identifies the amount of non-payroll operations and maintenance expense (O&M) in its filed test year revenue requirement that the utility forecasted using a general inflation estimate, as well as the estimated inflation rate percentage that the utility assumed to arrive at the test year projections. At hearing, a WEPCO witness suggested that the company's original filing was incorrect. However, WEPCO offered no better estimate of its non-payroll O&M related to inflation. It is, therefore, reasonable to apply the most recent estimated inflation rate to the \$265,000,000 originally identified by WEPCO as the "Total O&M Expenses Related to Inflation."

### **Removal of Certain Nonutility Investments from Equity**

The Commission finds that it is reasonable to continue the practice of removing nonutility investments which are not related to the provision of utility service from WEPCO's

average test year common stock equity, to arrive at utility common stock equity for purposes of determining revenue requirement. This practice protects ratepayers from risk by preventing the use of utility debt to fund nonutility investments. It is also consistent with the provisions in the Commission's orders authorizing investor-owned utilities to issue debt that limit the use of such debt to proper utility purposes.

### **Ratemaking Treatment for Property Held for Future Use**

For many years, the Commission has not permitted property held for future use to be included in rate base or to earn a return from ratepayers. This treatment is consistent with the principle of only including items in rate base that are "used and useful" in the provision of utility service. It also assumes that property held for future use earns its own return.

WEPCO presented testimony stating that there are compelling reasons why it should be allowed to earn a return on its investment in property held for future use. A WEPCO witness testified that, as its service territory becomes more urbanized, it is becoming increasingly difficult to procure land that is necessary for utility construction under reasonable terms, especially if the construction timeline is short. The company has determined it would be prudent and in the best interest of its customers to plan for and make land purchases further in advance of what has typically been done in the past. Currently, however, WEPCO faces a significant disincentive to do this because the Commission's current policy prohibits the company from earning a return on such investments over long periods of time.

Allowing WEPCO to earn a return on property held for future use would treat this investment as used and useful utility property. If the Commission were to authorize such treatment, some conditions would be necessary to protect ratepayers. If the Commission did authorize WEPCO to earn a return on its investment in property held for future use, WEPCO

would need to flow back to ratepayers any return, or income, generated by the property itself as well as any gains resulting from the sale of such property, so that both revenues and expenses associated with the investment are consistently treated as utility property.

In addition, if the Commission allowed WEPCO's property held for future use to earn a return as utility property, it would need to prohibit WEPCO from selling any such property to any of its affiliates and prohibit WEPCO from transferring any such property below-the-line for nonutility use. These restrictions would reduce the risk of ratepayers paying the carrying cost on property that may ultimately provide them no benefit.

These conditions are appropriate to protect ratepayers, although their enforcement could be difficult. In testimony, WEPCO indicated that it would prefer not to earn a return on its investment in property held for future use if the Commission included such conditions in its authorization. Thus, the Commission finds that it is reasonable to continue the practice of not including in revenue requirement a return on investment in property held for future use.

### **Limiting the Natural Gas Rate Increase to WEPCO's Requested Level**

In September 1999, WEPCO submitted a rate filing which included, among other things, a request to increase its natural gas rates in 2000 by \$8,000,000. The financial information filed by WEPCO in July 1999, however, showed a higher test year 2000 revenue deficiency for the company's natural gas operations of \$17,300,000. The Commission authorized a natural gas rate increase of \$11,608,000 in its interim order and, at the April hearings on WEPCO's final rates, the utility modified its position by requesting that it be allowed to recover the full amount of whatever revenue deficiency is ultimately determined by the Commission.

Wisconsin End-User Gas and Electric Association (WEUGEA) and the Citizens' Utility Board (CUB) recommended that the Commission authorize a rate increase no greater than the

amount in WEPCO's September 1999 rate filing (\$8,000,000). These parties provided evidence that WEPCO never notified the Commission, the parties in this proceeding, or its customers that it was seeking more than an \$8,000,000 rate increase for its natural gas operations, even after Commission staff's estimated natural gas revenue deficiency was known.

It is reasonable to authorize a rate increase for WEPCO's natural gas operations equal to the amount the company requested in its application, because WEPCO did not amend its application or notify its customers that it was seeking a larger natural gas rate increase. In addition, doing so allows some of the merger savings from the WEC/WICOR merger to be captured for ratepayers.

Since this natural gas revenue increase is smaller than the amount previously authorized as an interim rate increase, WEPCO shall refund the amount of natural gas revenues collected from the interim rates authorized in this docket that exceed the amount that would have been collected during that period under final rates authorized in this order. WEPCO shall file the calculation of its proposed refund for each rate class, including a narrative explanation of how and when such refund will be returned to ratepayers, within 60 days of the effective date of this order. The refund shall be returned to customers prospectively, in a manner similar to the methodology used for pipeline refunds. Individual customer refunds shall also include the sales tax associated with the refund.

### **MGP Clean-up Costs**

In 1993, the Commission developed guidelines for accounting for manufactured gas plant (MGP) site clean-up costs. The guidelines, which were updated in April 1996 and February 1999, were shaped by concerns about rate impacts, cash flow and capital structure impacts, intergenerational equity, and the biennial rate case process. In WEPCO's past rate proceedings,

as well as other utilities' rate proceedings, the Commission has found that sharing MGP costs between ratepayers and shareholders is reasonable. The sharing is achieved by means of deferred accounting with recovery of costs in rates amortized over a period of four to six years, but with no recovery in rates of the carrying costs on the unamortized balance.

WEPCO's filed natural gas revenue requirement included amortization expense of \$444,288 for MGP site clean-up costs. Based on its review of actual clean-up expenditures through December 31, 1998, the Commission accepts the company-estimated test year amortization expense. This expense consists of \$309,684 relating to the existing amortization of 1995 and 1996 deferred costs and \$134,604 relating to the amortization of 1997 and 1998 deferred costs over a five-year period, beginning with the effective date of this order. The amortization does not include any amounts related to recent circuit court judgments related to a West Allis, Wisconsin site.

### **Natural Gas Sales Promotion**

WEPCO filed a 2000 test year budget of \$160,000 to continue funding its Natural Gas Vehicle Program (NGVP) for fleet vehicle operations. WEPCO's program may benefit southeastern Wisconsin ratepayers by reducing airborne pollutants associated with the combustion of fossil fuels such as gasoline. In order for the Commission to determine whether continued ratepayer funding is appropriate for this utility activity, it is necessary and reasonable to require WEPCO to conduct an evaluation of the effectiveness of its NGVP program, as described in its approved evaluation plan. The Commission finds the proposed budget of \$160,000 reasonable for the 2000 test year under these conditions.

### **Natural Gas and Steam Operations**

In its July 6, 1999, filing of projected financial data for the 2000 test year, WEPCO estimated it would have a revenue deficiency for each of its steam service areas, but its September 1999 application requested no change to its steam service rates. Accordingly, the Commission authorizes no change in rates for WEPCO's steam operations. In its July 1999 filing, the company also estimated it would have a larger revenue deficiency for its natural gas operations than the natural gas rate increase it subsequently requested in its September 1999 application. The test year natural gas revenue deficiency is larger than the increase requested by the company for its natural gas operations, but the Commission has found it reasonable (see above) to authorize a natural gas increase equal to the amount requested by WEPCO in its application. For purposes of this proceeding, the revenues that will be produced during the test year for WEPCO's natural gas and steam operations are reasonable. Because the revenue deficiencies for WEPCO's natural gas and steam operations are not being used for determining rates in this proceeding, the financial schedules used to calculate the revenue deficiencies for those operations are not presented in this order.

### **Summary of Income Statement**

In addition to the findings regarding the specific items discussed above, all other Commission staff estimates and adjustments to the company's estimates are reasonable and just. Accordingly, estimates of 2000 Wisconsin retail electric operations that are considered reasonable and just for purposes of determining the revenue requirement in this proceeding are as follows:

## 2000 Test Year

## Electric Operating Income Statements

	Total Company Electric (000's)	Wisconsin Retail Electric (000's)
Revenues:		
Electric Sales Revenues	\$1,630,284	\$1,472,067
Opportunity Sales Revenues	48,956	41,826
Other Operating Revenues	14,931	13,689
Total Operating Revenues	<u>\$1,694,171</u>	<u>\$1,527,582</u>
Operating and Maintenance Expense:		
Fuel	\$318,131	\$271,582
Purchased Power	121,991	105,744
Other Production	223,971	196,313
Transmission	10,771	8,796
Distribution	71,032	65,794
Customer Accounts	32,966	32,471
Customer Service	31,947	31,556
Sales	-	-
Administrative and General	162,779	148,111
Total Operating and Maintenance Expense	<u>\$973,588</u>	<u>\$860,367</u>
Depreciation	\$266,745	\$240,770
Taxes Other Than Income Taxes	81,745	76,002
Federal Income Taxes	99,993	94,407
State Income Taxes	21,536	20,262
Deferred Income Taxes	(6,727)	(5,712)
Investment Tax Credits	(4,025)	(3,656)
Total Operating Expense	<u>\$1,432,855</u>	<u>\$1,282,440</u>
Net Operating Income	\$261,316	\$245,142
Adjustment to Operating Income	<u>23,437</u>	<u>20,025</u>
Net Adjusted Operating Income at Current Rates	<u>\$284,753</u>	<u>\$265,167</u>

## **Net Investment Rate Base**

### **Nitrogen Oxide Expenditures**

On March 3, 2000, the Commission issued its order in docket 05-CE-108, the generic docket to address nitrogen oxide (NOx) issues. In that order, the Commission authorized investor-owned utilities to depreciate assets used for NOx control over ten years, a shorter period than the useful life of the asset. In addition, the Commission's order in docket 05-CE-108 allows utilities to propose escrow accounting in rate cases for NOx expenditures.

In this proceeding, WEPCO requested that NOx expenditures be treated, for rate recovery, the same as any other construction expenditure. That is, WEPCO opposes escrow accounting for this activity. In addition, WEPCO requested a 100 percent current return on CWIP for NOx expenditures.

The Commission finds that, because of the significant uncertainty that exists regarding the level of expenditures that may be necessary to address this issue as well as the timing of those expenditures, it is reasonable for WEPCO to record AFUDC on 100 percent of NOx-related CWIP. In addition, because of the uncertainty regarding the level and timing of these expenditures, it is reasonable for WEPCO to establish an escrow mechanism for all revenue requirement components, including income taxes, associated with its NOx remediation expenditures. Based on WEPCO's most recent forecast of its NOx remediation construction expenditures, it is reasonable to increase Wisconsin retail electric revenue requirement for 2000 and 2001 by \$3,689,000 and \$13,715,000, respectively.

### **Reliability and Safety Construction Expenditures**

In its initial direct testimony, filed in September 1999, WEPCO proposed a limited issue rate proceeding in which it sought a rate increase for its electric and natural gas operations for

test year 2000 and an additional rate increase for its electric operations in 2001. In addition to providing recovery for the expiration of a large negative amortization expense associated with contributions in aid of construction, the company requested these increases to recover the costs associated with its plans to increase construction related to enhancing reliability and safety in its electric and natural gas operations. The amounts WEPCO requested to recover in its September filing for its reliability and safety expenditures are \$33,000,000 in 2000 and an additional \$16,000,000 in 2001 for the company's retail electric operations, as well as \$2,000,000 in 2000 for its natural gas operations.

Since WEPCO expected these reliability and safety construction expenditures to be higher than historical construction levels, the company offered to refund any revenues it collects associated with estimated electric reliability and safety construction expenditures in 2000 and 2001 that are greater than its actual expenditures. The company did not, however, provide any testimony regarding the details of what, specifically, would be subject to refund or how the need for such a refund would be evaluated. Thus, Commission staff developed several alternatives for the Commission to consider regarding the issue of making electric safety and reliability construction expenditures subject to refund.

The Commission finds that the Wisconsin retail electric revenue requirement calculated by Commission staff for the 2000 test year includes the test year cost of WEPCO's electric reliability and safety expenditures. It is reasonable to increase Wisconsin retail electric rates in 2001 by \$13,806,000 to allow the company to recover its costs in 2001 associated with its incremental electric reliability and safety construction expenditures.

Electric safety and reliability expenditures are defined as all electric construction expenditures except for construction related to line extensions for new customers, and

construction expenditures required as a result of a governmental mandate. It is reasonable to make both 2000 and 2001 electric reliability and safety construction expenditures subject to refund. It is also reasonable to evaluate the need for a refund at the end of the two-year period, by comparing the company's actual construction expenditures for electric reliability and safety in total over the two years, compared to the forecasted level for the two years. This approach measures the expenditures in both years, but will not penalize the company if it, for example, spends less than its estimate in the first year and spends more than its estimate in the second year to make up the difference.

In addition, it is reasonable for WEPCO to earn a current return, calculated using the economic cost of capital of 14.10 percent,<sup>1</sup> on 100 percent of CWIP associated with electric reliability and safety construction expenditures. A current return on CWIP will allow the evaluation of the need for a refund to be focused on whether the company achieved its forecasted level of construction expenditures rather than whether it accurately forecasted the timing of when the plant would go into service. In addition, a current return on CWIP provides an incentive for the company to spend the amount it forecasted for electric reliability and safety.

Within one month following the effective date of this order, WEPCO shall submit to the Commission a report showing its 2001 forecasted expenditures for electric reliability and safety by project, including a brief description of each project. In addition, WEPCO shall submit quarterly reports for the 2000-2001 biennial period showing its forecasted expenditures compared to its actual expenditures for electric reliability and safety construction. These quarterly reports shall include a written explanation for any material variances.

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<sup>1</sup> The economic cost of capital is the adjusted weighted cost of capital of 10.18 percent, adjusted to include the effect of income taxes.

**Summary of Net Investment Rate Base**

In addition to the findings regarding the specific items discussed above, all other Commission staff estimates and adjustments to the company’s estimates are reasonable and just. Accordingly, estimates of 2000 total company and Wisconsin retail electric average net investment rate base that are considered reasonable and just for purposes of determining the revenue requirement in this proceeding are as follows:

**Net Investment Rate Base**

	Total Company Electric (000's)	Wisconsin Retail Electric (000's)
Plant in Service	\$ 5,555,326	\$ 5,057,548
Accumulated Depreciation	<u>(2,914,173)</u>	<u>(2,611,617)</u>
Net Plant In Service	\$ 2,641,153	\$ 2,445,931
Fuel Inventory	\$ 100,705	\$ 85,839
Materials and Supplies Inventory	70,451	64,208
Deferred Taxes	(379,311)	(347,107)
Customer Advances	(33,928)	(31,580)
Net Decommissioning Fund	<u>577,192</u>	<u>492,356</u>
Average Net Investment Rate Base	\$ <u><u>2,976,262</u></u>	\$ <u><u>2,709,647</u></u>

**Pro Forma Rate of Return**

Estimated operating income for the 2000 test year at present rates would result in a rate of return on net investment rate base of 9.79 percent for Wisconsin retail electric operations.

**Inflation Rates**

A test year revenue requirement based on an inflation rate of 3.1 percent for the test year is reasonable. This inflation rate is based on the average of current estimates for 2000 from the monthly publication of Review of the U.S. Economy, from Standard and Poor’s DRI, and from

the Blue Chip Financial Forecasts newsletter. This is a reasonable and objective method of determining the expected rate of inflation.

### **Capital Structure**

In prior rate orders the Commission has determined that off-balance-sheet financing should be included when determining appropriate debt and equity levels for public utilities, but not in setting utility rates. A reasonable utility rate making capital structure for the test year consists of 53.45 percent common equity, 0.86 percent preferred stock, 42.61 percent long-term debt, and 3.08 percent short-term debt. When consideration is given to the off-balance-sheet financing in the test year, the utility financial capital structure will consist of 50.80 percent common equity, 0.81 percent preferred stock, 45.48 percent long-term debt and debt equivalents, and 2.91 percent short-term debt. Both the financial and the rate making capital structures are reasonable for the test year.

The Commission finds that a long-term range of 48.50 percent to 53.50 percent for the utility's common equity ratio is reasonable and provides adequate financial flexibility at this time. The Commission considered increasing the long-term common equity ratio range, but the costs and benefits of doing so are unclear. Consequently, it is reasonable to adopt the same guideline used in WEPCO's prior rate case. The exact level of the utility common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing the utility at a given time. WEPCO should attempt to operate within that range in the long term.

Assessing the reasonableness of the utility's capital structure depends upon three important principles. First, capital structure decisions must be based on the utility's needs, not on the needs of the nonutility operations of the holding company. Second, the capital structure

should provide adequate flexibility to the utility and to the Commission to allow proper utility investment now and in the future. Third, the dividend policy of the utility should be similar to typical electric utility dividend practices as long as the utility is below the estimated test year common equity ratio.

The utility's needs must take precedence over nonutility needs if ratepayers are to be protected. Wis. Stat. § 196.795 clearly requires the Commission to protect ratepayers from utilities that grant a higher priority to nonutility needs. The identification of utility needs goes beyond foreseeable needs. The utility must have flexibility to finance both foreseen and unforeseen capital requirements.

### **Dividend Restriction**

In docket 9402-YO-100, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before nonutility needs in capital structure and dividend policy choices. Protection of the ratepayers' interest and the utility needs requires a capital structure and dividend policy which maintains the projected test year financial integrity of the utility. This can be partially accomplished by paying no more than a typical utility dividend or, in this case, the estimated dividends used in determining the test year average capital structure. Such a dividend policy will serve to maintain the utility common equity ratio near the test year authorized level in the event other forecasts are realized. Attempting to maintain the utility common equity ratio near the test year authorized level is important since ratepayers are paying for that level of equity. Therefore, proper ratepayer protection requires that no dividend payments in excess of those forecasted in this case be paid prior to the end of the test year. At the end of the test year, a special dividend may be paid in excess of the forecasted dividends only

if the additional payment does not reduce the average test year rate making common equity ratio below the forecasted level of 53.45 percent.

Similarly, in annual periods subsequent to the 2000 test year, ratepayer protection requires that no dividends in excess of a typical utility dividend be paid prior to the end of each year. At the end of each year, a special dividend may be paid in excess of a typical utility dividend only if the additional payment does not reduce the average annual rate making common equity ratio below the test year forecasted level of 53.45 percent.

### **Short-Term Debt**

A reasonable estimate of the cost of short-term debt for the test year is 6.80 percent. This forecast is based on the average of test year estimates provided by the Blue Chip Financial Forecasts newsletter. This is a reasonable and objective method of determining the short-term debt cost.

### **Variable Rate Bonds**

A reasonable estimate of the test year interest rate on the Oak Creek Bonds and other variable rate bonds is 4.80 percent for the test year. This estimate factors in the tax-free aspects of the bonds, using the forecasted Treasury Bill rate from Blue Chip Financial Forecasts and an estimate of the applicable yield spread. This is a reasonable and objective method of determining the variable-rate debt cost.

### **Return on Common Equity**

This issue was not contested in this proceeding. Consequently, the Commission's prior authorized return on equity of 12.20 percent from docket 6630-UR-110 remains in effect. In

view of this consideration, the Commission finds a 12.20 percent return on utility common stock equity to be reasonable and just in this proceeding.

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	\$1,899,552	53.45	12.20%	6.52%
Preferred Stock	30,450	.86	3.95%	.03%
Long-Term Debt	1,514,371	42.61	7.07%	3.01%
Short-Term Debt	<u>109,359</u>	<u>3.08</u>	6.80%	<u>.21%</u>
Total Utility Capital	<u>\$3,553,732</u>	<u>100.00</u>		<u>9.77%</u>

The weighted cost of capital of 9.77 percent is reasonable for WEPCO for the test year. It generates an economic cost of capital of 14.10 percent and a pre-tax interest coverage ratio of 4.38 times.

**Ten-Year Financial Forecasts**

The applicant’s base-case ten-year financial forecast is useful to the Commission and should be submitted in future rate cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements. This finding does not preclude the utility or other parties from also submitting other financial forecasts in future WEPCO rate cases.

**Construction Work in Progress (CWIP)**

Given WEPCO’s financing and cash flow requirements in the test year and forecasted amount of construction activity, the Commission finds it is reasonable to allow a current return

on 50 percent of CWIP for the test year, except for CWIP associated with NO<sub>x</sub> remediation and electric reliability and safety construction expenditures, as defined in this order. It is reasonable for WEPCO to accrue AFUDC at the adjusted weighted cost of capital of 10.18 percent on all CWIP associated with NO<sub>x</sub> remediation and to earn a current return on all CWIP associated with electric reliability and safety construction.

### **Rate of Return on Rate Base**

The 9.77 percent composite cost of capital must be translated into a rate of return, which can then be applied to average net investment rate base and used to compute the overall return requirement in dollars. The estimate of WEPCO's average net investment rate base plus construction work in progress and conservation investments for the test year is 95.99 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to average net investment rate base.

To allow a test year current return on the average CWIP balance, an adjustment must be added to the return on net investment rate base. In addition, an adjustment to the return requirement on retail electric net investment rate base is needed to provide WEPCO with a return on the average capitalized conservation balance.

The reasonable and just rates of return on average Wisconsin retail electric net investment rate base for ratemaking purposes in this proceeding, computed on the basis of the above findings, are as follows:

	Wisconsin Retail Electric
Weighted Cost of Capital	9.77%
Average Percent of Utility Net Investment Rate Base Plus CWIP and Conservation Investments to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	95.99%
Percent Return Requirement Applicable to Net Investment Rate Base Adjustment to Return Requirement to Provide a Return on Capitalized Conservation Investments	0.12%
Adjustment to Return Requirement to Provide a Current Return on 100 Percent of Reliability and Safety CWIP and 50 Percent of Remaining CWIP Excluding NOx CWIP	0.22%
Adjusted Percent Return Requirement on Net Investment Rate Base	10.52%

**Revenue Requirement**

The Commission finds that an increase in natural gas revenues of \$8,000,000 is reasonable. It is also reasonable to authorize no change in rates for WEPCO’s two steam service areas. Based on the above findings, an increase in Wisconsin retail electric revenues of \$36,538,000, which includes an adjustment for test year costs associated with NOx remediation, is reasonable and just. This amount is computed as follows:

	Wisconsin Retail Electric (000's)
Return on Average Net Investment Rate Base at Present Rates	9.79%
Required Return on Average Net Investment Rate Base	10.52%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	0.73%
Average Net Investment Rate Base	\$2,709,647

	Wisconsin Retail Electric (000's)
Amount of Earnings Deficiency on Average Net Investment Rate Base	\$19,780
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes	\$32,849
Adjustment to Revenue Deficiency for Costs Related to Nitrogen Oxide Remediation	\$3,689
Adjusted Revenue Deficiency	\$36,538

In addition, it is reasonable to authorize an additional rate increase of \$27,521,000 for Wisconsin retail electric operations to be effective January 1, 2001. This additional increase is necessary to allow the company to recover its incremental costs in 2001 associated with NOx remediation and electric reliability and safety construction.

### **Changes to the Electric Cost-of-Service Study**

Changes to the Cost-of-Service Study (COSS) were a point of discussion in this proceeding. CUB proposed modifications to the WEPCO COSS and advocated abandoning the use of the Minimum System Method in the COSS. CUB also asked that various allocation percentages be changed in the COSS prepared by WEPCO. The Wisconsin Industrial Energy Group (WIEG) and CUB asked that the same 27 classes be used in the COSS as are used for rate design. WIEG also requested that the Commission consider only a company COSS that uses demand allocators based upon an average of three summer month coincident peaks (3 CP), rather than considering a company COSS that uses the average of 12 monthly coincident peaks (12 CP).

Insufficient evidence was presented to abandon the use of the Minimum System Method. It is reasonable to continue to use a 12 CP COSS, rather than the 3 CP COSS as proposed by WIEG, to maintain rate stability and comparability between utilities. In addition, the details shown in a COSS report that is expanded to 27 rate classes would likely confuse more than clarify costs to serve each rate class, and could mask existing rate interrelationships.

The current practice of the Commission is to review a range of COSS and then consider this range in its revenue allocation decisions. Each of the various arguments put forth concerning changes in the COSS has merits and flaws. However, each COSS has a unique set of assumptions that provides the Commission with a slightly different perspective on revenue allocation. It is reasonable continue the current practice of reviewing a range of COSS and to base revenue allocation decisions on this overview.

### **Electric Revenue Allocation and Rate Design**

A variety of revenue allocations was presented to the Commission. WEPCO's initial position was to increase each rate component by approximately the same percentage. This results in a uniform increase in allocation of revenue responsibility. Commission staff provided two revenue allocations. The first alternative increases revenue uniformly for all classes in both Step One and Step Two,<sup>2</sup> just as initially proposed by WEPCO. The second alternative increases revenue responsibility for all classes except Industrial Power (Cp) Classes in Step One. As part of Step One, industrial energy rates are adjusted using the five-year marginal energy cost as a guideline. Low load factor industrial customers may see an increase in rates during this

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<sup>2</sup> Step One refers to the 2000 electric rate increase and Step Two refers to the electric rate increase that will become effective January 1, 2001.

realignment. The second alternative increases the revenue responsibility of all classes uniformly during Step Two.

CUB advocated the use of the revenue-cost ratio to shift revenue in a manner that would minimize impact on residential customers and move all classes within 5 percent of a 100 percent revenue/cost ratio. WIEG recommended revenue responsibility changes that would reduce interclass subsidies to one-half of their present level and limit the subsidies to less than 5 percent. WIEG's changes would benefit most industrial power customers. Both CUB and WIEG called for increases in revenue from Low Voltage Cp-1 rates and proposed a greater decrease to lighting and small commercial classes than is given to other classes.

A partial revenue allocation scheme was presented by Mr. Arthur Johnson, a customer of the applicant under the Farm, Fg-1 rate class. Mr. Johnson proposed to freeze Farm, Fg-1 rates and transfer Farm revenue responsibility to Residential customers. The Commission considers the existing rate relationship between the Residential and Farm rate classes to be appropriate. The adoptions of Mr. Johnson's rate proposal would negatively affect that relationship and, as such, is not adopted in this proceeding. A more appropriate forum for addressing farm customers' need to control costs is the Public Benefits initiative.

Based in part on the various COSS results, the Commission adopts the second Commission staff alternative. This revenue allocation gives all classes, except the Cp classes, a uniform increase in revenue allocation in Step One while adjusting Cp energy rates toward five-year average marginal cost. The Step Two change of this revenue allocation is an across-the-board uniform increase in revenue allocation for all classes. The authorized revenue allocation and rates associated with this decision are shown in Appendix B.

This revenue allocation adjusts Cp rates by moving the energy charges of the Cp classes toward the five-year average marginal cost of energy. Historically, the Commission has used the five-year average marginal cost of energy as a guideline for establishing the energy rates of the Cp classes. The Commission finds it reasonable to continue this policy in this docket.

Commissioner Mettner dissents from this revenue allocation and supports a uniform, across-the-board increase in revenue and rates.

Mr. Michael Mangan of Emerald Energy, L.L.C. (Emerald) asked the Commission in this docket to remove, or increase, the 20 kW net metering cap of the Customer-Owned Generation net metering rate (COGS-2). Emerald also requested that any net excess generation be annualized and paid to the customer at avoided cost. More information is needed before this issue can be properly addressed.

### **Natural Gas Cost of Service Studies**

Several parties raised questions about the appropriateness of specific cost-of-service studies, or about specific allocations within cost-of-service studies. Some parties asked the Commission to rely on some cost-of-service studies and to ignore others.

It is reasonable to consider all cost-of-service studies as a guide to setting rates. This has been the Commission's policy in the past and it continues to be the appropriate policy.

### **Natural Gas Contractual Swing Quantity (CSQ) Balancing Service**

The contractual swing quantity (CSQ) approach to pricing natural gas balancing service involves the use of fixed and volumetric charges. It is a departure from the traditional balancing service that was established in the Commission's generic docket 05-GI-105. The traditional approach involves only volumetric charges.

The Commission does not find it to be reasonable at this time for WEPCO to implement its proposed CSQ balancing service. The Commission approved the CSQ balancing approach in WEPCO's prior rate case, but that approval was vacated by the Dane County Circuit Court on an appeal. The record contains insufficient evidence to warrant the imposition of the CSQ approach now. If WEPCO believes that this approach is preferable to the traditional balancing method, it should continue to refine the CSQ method for future consideration by the Commission.

### **Natural Gas Balancing Tier Ranges**

WEPCO, like many other LDCs, has balancing and cashout tiers for natural gas service. These tiers allow WEPCO to charge progressively more for imbalances that are significant relative to what it charges for those that are close to the nomination.

It is reasonable to use the same balancing tier ranges for both daily balancing and daily cashout. This provides symmetry and consistency between the balancing and cashout procedures. The approved ranges are: (1) 0 to 10 percent; (2) greater than 10 percent to 25 percent; and (3) greater than 25 percent. Since the CSQ approach is not being implemented in this case, WEPCO should submit to the Commission a proposed volumetric-only balancing pricing mechanism to the Commission. WEPCO should submit such a proposal by September 15, 2000, for approval. The balancing proposal should be designed to be implemented on or before November 1, 2000.

### **Charges for Natural Gas Customer Imbalances in the Same Direction of a Constraint**

When a constraint day is called, natural gas transportation customers are held to their confirmed nomination and daily balancing service is not available from the utility. On a high

flow constraint day any use by the transportation customer in excess of its nomination is unauthorized use.

It is not reasonable for WEPCO to charge a transporter on a constraint day both unauthorized use penalties and balancing charges on the same imbalance. On constraint days only unauthorized use penalties should apply to such imbalances. Those penalty charges are relatively high and should be sufficient to send an economic signal to transporters that such imbalances are to be avoided. Commissioner Mettner dissents.

### **Conditions For Calling Constraint Days for Natural Gas Service**

It is reasonable to limit the calling of system-wide<sup>3</sup> constraints for natural gas service to situations where the utility is experiencing or is likely to experience some operational problem (e.g., limited natural gas commodity or capacity, pipeline issued limitations, distribution capacity constraints, or too much natural gas at the city gate). That is not to say, however, that WEPCO should discontinue its attempts to alter the behavior of marketers or transporters who are gaming the system. Selective constraints, which can be applied to individual transporters or marketers, should be used to address economic problems, such as price arbitrage. WEPCO's tariffs should explicitly recognize the distinction between operational problems and economic problems when calling a constraint.

### **Daily Cashout With WACOG Pricing**

It is reasonable for WEPCO to continue to use a daily cashout process with a weighted average cost of gas (WACOG) based price to reduce the potential for arbitraging gas supplies.

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<sup>3</sup> The term "system-wide" may pertain to only a portion of the utility's distribution system if the physical problem is limited to specific areas.

The traditional method of cashout, which is done on a monthly basis, clearly creates arbitrage opportunities when WACOG is the cashout basis. When a daily cashout process is used, the WACOG price effect is muted. WEPCO should continue to explore the possibility of implementing a market-based cashout pricing mechanism in the future.

### **Firm Versus Interruptible Cashout Pricing for Natural Gas Service**

Prior to the elimination of interruptible distribution service for most customers in the prior rate case, WEPCO cashed out a large proportion of its transportation customers at interruptible rates. An interruptible cashout rate is noticeably lower than a firm cashout rate because the interruptible rate does not contain pipeline peak demand charges. When WEPCO eliminated its interruptible distribution service for all customers except power generators, it began cashing out all customers except power generators at firm rates.

It is not reasonable for WEPCO to continue to cashout all of its transportation customers at firm rates. The fact that a customer is firm for distribution reasons does not necessarily indicate that the customer takes firm gas supplies. In fact, the marketers have indicated that many customers continue to take interruptible gas supplies. It is reasonable, therefore, for WEPCO to use a blended rate that is based on both firm and interruptible natural gas prices for this process. The firm and interruptible proportions should be based on some reasonable estimate of the actual mix of firm and interruptible transportation supplies. If no better estimate can be found, the 21 percent firm/79 percent interruptible mix discussed in the record for this case would be appropriate. It is reasonable that the approval of the appropriate cashout pricing mechanism be delegated to the administrator of the Natural Gas Division for approval. WEPCO should submit a proposal to the administrator by October 1, 2000. The revised cashout process should be implemented no later than November 1, 2000.

### **Cashout by Class for Natural Gas Service**

It is reasonable that WEPCO continue to cashout customers by class to reflect the different effective rates for each class. To require WEPCO to cashout all of its customers at a single rate would prevent it from reflecting the differential costs associated with serving customers of different sizes.

### **Super Pooling for Natural Gas Service**

Since the existing super-pooling tariff has attracted no customers, it has failed to mitigate the impact on transportation customers of the implementation of the ten operating zones approved in the last rate proceeding. It is, therefore, reasonable for WEPCO to work with interested parties and the Commission staff to develop a more workable super-pooling tariff. The revised tariff should be implemented no later than April 1, 2001. The Commission, without prejudice to the merits, makes no determination at this time as to the appropriateness of deferred accounting for WEPCO's costs associated with development of the super-pooling tariff.

### **Operational Zones for Natural Gas Transportation Service**

It is reasonable for WEPCO to continue to use its operational zone approach in dealing with transporters on its system. Those zones require marketers and transporters to abide by the physical constraints of the WEPCO system when delivering gas and pooling customers. No evidence appears in this record that would suggest that the zone approach, which was approved in the prior rate order for WEPCO, should be revised or eliminated.

### **Lost and Unaccounted For Natural Gas**

WEPCO was ordered in the prior proceeding to submit a study concerning the feasibility of allowing transporters the option of making up lost and unaccounted for natural gas in kind

rather than by paying a fee (rate) for this natural gas. WEPCO did not submit the study in this case. It did, however, propose to lower the fee for this natural gas by 30 percent, perhaps in an attempt to address the transporters ultimate concern about paying too much for lost natural gas.

It is reasonable that WEPCO submit to the Commission its study of the possibility of allowing transportation customers to replace lost and unaccounted for natural gas with natural gas in kind rather than paying a separate rate to recover the costs associated with that natural gas. The Commission staff should review the study and then provide the Commission with options as to how to proceed on this issue. It is reasonable that the cash payment charge for lost and unaccounted natural gas be lowered from \$0.0020 per therm to \$0.0014 per therm. This does, at least in economic terms, provide the end result desired by the transporters.

#### **Natural Gas Distribution Capacity Crediting Service**

It is reasonable that the maximum credit for customers participating in WEPCO's Distribution Capacity With or Without Gas Supply Interruption Crediting Service be set at each class's total effective volumetric margin rate. This allows for a better reflection of costs than is allowed under the current \$0.0300 per therm flat rate maximum across all classes.

#### **Natural Gas Transportation Service Nomination Deadlines**

In order for transporters to take maximum advantage of any information they receive prior to the pipelines' nomination deadlines, the lead time required for the transporter to provide the utility with the nomination must be minimized. It is reasonable that WEPCO reduce the lead times required for transporters nominations. Currently, WEPCO requires transporters to submit their nominations two hours prior to the pipelines' deadlines. In order for transporters to make more efficient use of the nomination process, these lead times should be reduced to 1.5 hours

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before the initial nomination deadline and 1.0 hour before each of the intra-day nomination deadlines. WEPCO should also continue to explore means of further reducing these lead times in the future.

### **Non-Telemetered Natural Gas Transportation Pilot**

It is not reasonable for the Commission to order WEPCO to implement a specific non-telemetered transportation program at this time. WEPCO, as part of the requirements of the prior rate order, has properly submitted to the Commission outside this record a non-telemetered transportation proposal. It is, therefore, inappropriate to act on this matter in this proceeding.

### **Notice Requirement for Moving From Natural Gas Sales to Transportation Service**

WEPCO currently requires sales customers to give 12-month's notice prior to November 1 of a given year of their intent to switch from sales service to transportation service. This allows the LDC some time to restructure its supply contracts in keeping with the changes in customer service choices.

It is reasonable for WEPCO to retain its current notice requirement for customers switching from sales to transportation service. The current rules provide the maximum amount of notice required. WEPCO should continue its efforts to reduce the notice requirements where feasible.

### **Natural Gas Interruptible Sales Service Pricing**

In this proceeding, some marketers claimed that WEPCO was under pricing its interruptible sales service. They offered evidence comparing WEPCO's rates to publicly available rates. In the order in docket 6630-UR-110, the Commission determined that WEPCO

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could continue to price its interruptible sales service based on traditional methods unless WEPCO's share of the market for such customers increased.

It is reasonable for WEPCO to continue to price its interruptible sales service as it has in the past. There is no convincing evidence that WEPCO is under pricing this service, in light of the fact that the net effect is that customers are leaving the service, not signing up for it.

WEPCO should continue to monitor the trends in customer counts and sales volumes for this service.

### **Natural Gas Large Commercial/Industrial Classes**

WEPCO proposed to implement to new rates classes for its largest commercial/industrial firm customers. These customers most often use natural gas for process loads, as opposed to space heating, and, therefore, tend to have some of the highest load factors on the system. All else equal, the higher the load factor, the less it costs to serve a customer. It is reasonable for WEPCO to establish the new Cg-6/Ct-6 and Cg-7/Ct-7 rate classes.

It is also reasonable that these classes be given lower rates than the Cg-5/Ct-5 class because the customers in the Cg-6/Ct-6 and Cg-7/Ct-7 classes have better (i.e., higher) load factors and use higher volumes, which makes them less costly to serve. Commissioner Mettner dissents.

### **Natural Gas Rate Design**

The natural gas rates found in Appendix C appropriately reflect the Commission's decisions in this case. The rates are just and reasonable.

## **Order**

1. This order shall be effective one day after the date of mailing. The authorized rates and rules shall also be effective on the same date, provided that the rates are filed with the Commission and placed in all offices and pay stations of the utility by that date. If the authorized rates and rules are not placed in all offices and pay stations by the effective date of the order, the rates shall become effective on the date that the rates are placed in all offices and pay stations. WEPCO shall prepare bill inserts which appropriately identify the rates authorized herein. WEPCO shall distribute the inserts to customers with the first billing containing these rates and shall file copies of these inserts with the Commission before it distributes the inserts to customers. WEPCO shall distribute these inserts to customers with the first billing containing the rates authorized in this order.

2. The authorized rates in Appendices B and C shall be in effect until the issuance of an order by the Commission establishing new rates. WEPCO shall apply the rates specified in Step Two of Appendix B to bills rendered for retail electric service under jurisdiction of the Commission beginning January 1, 2001.

3. The fuel costs in Appendix D shall be used for monthly monitoring of WEPCO's fuel costs, pursuant to Wis. Admin. Code ch. PSC 116.

4. WEPCO shall report monthly to the Commission its actual total system cost of generation, purchased energy, capacity, and wheeling costs less the revenues from opportunity sales of energy and capacity. WEPCO shall otherwise comply with the fuel cost determination and monitoring system as set forth in the Findings of Fact.

5. WEPCO shall record a revenue amortization for SO<sub>2</sub> emission allowance revenues of \$1,721,515 and an amortization expense for SO<sub>2</sub> of \$1,150,000 on an annual total company basis.

6. WEPCO shall refund to customers any natural gas revenue it collected during the period in which interim rates authorized in this docket were in effect that exceeds the revenue that it would have collected under the final rates authorized in this order. WEPCO shall file the calculation of its proposed refund for each rate class, including a narrative explanation of how and when such refund will be return to ratepayers, within 60 days of the effective date of this order. The refund shall be returned to customers prospectively, in a manner similar to the methodology used for pipeline refunds. Individual customer refunds shall also include the sales tax associated with the refund.

7. For the year 2000, WEPCO shall record one-time DSM expense accruals of \$2,858,920 for electric operations and \$328,993 for natural gas operations as well as the associated income taxes to correct the escrow balances. These accruals shall be recorded in 2000 in addition to the DSM accruals included in the test year revenue requirements for Wisconsin retail electric operations and Wisconsin natural gas operations.

8. Beginning with the effective date of this order, WEPCO shall record annual DSM accrual amounts of \$12,853,228 for electric operations (\$14,128,367 of authorized expenditures less \$1,275,139 of amortized underspending) and \$5,601,022 for natural gas operations (\$4,894,218 of authorized expenditures plus \$706,804 of amortized overspending). WEPCO shall continue to record these amounts until the Commission authorizes new DSM accrual amounts.

9. WEPCO shall amortize its remaining deferred DSM expenditures over a four-year period, by recording an annual deferred DSM amortization expense of \$5,628,000. The company shall continue recording this amortization expense until its deferred DSM balance equals zero.

10. WEPCO shall record AFUDC on 100 percent of its average test year construction work in progress associated with construction expenditures for NOx remediation in 2000 and 2001, calculated at the adjusted weighted cost of capital rate of 10.18 percent, plus applicable income taxes.

11. WEPCO shall establish an escrow mechanism for all revenue requirement components, including income taxes, associated with its NOx remediation expenditures. This escrow mechanism shall track the company's actual costs for this activity compared to the amounts it is recovering in rates of \$3,689,000 and \$13,715,000 in 2000 and 2001, respectively.

12. WEPCO may not record AFUDC for any CWIP associated with its electric reliability and safety construction expenditures, as described above in the Opinion section of this order, until the Commission issues a new order changing the treatment of such CWIP.

13. WEPCO shall record AFUDC on 50 percent of its average CWIP, excluding CWIP associated with NOx remediation and electric reliability and safety construction expenditures.

14. The revenue requirements associated with WEPCO's "electric reliability and safety construction expenditures," as described above in the Opinion section of this order, are subject to refund.

15. WEPCO shall submit quarterly reports for the 2000-2001 biennial period comparing actual and forecasted levels of electric reliability and safety construction expenditures, as defined above in the Opinion section of this order.

16. WEPCO shall submit a report to the Commission showing its forecasted electric construction expenditures associated with reliability and safety for 2001 by project. This report shall be submitted within one month of the effective date of this order.

17. WEPCO shall conduct an evaluation of the effectiveness of its Natural Gas Vehicle Program as described in its approved evaluation plan. WEPCO shall submit the evaluation results from its historical program activity (1997-1999) within 90 days of the date of this order. WEPCO shall submit the evaluation results from its future program activity (2000-2001) no later than April 30, 2002.

18. WEPCO shall submit a ten-year financial forecast in its next rate case before this Commission.

19. WEPCO may not pay dividends in excess of the amount forecasted in this case if they cause the average annual rate making utility common equity ratio to fall below the test year authorized level of 53.45 percent.

20. WEPCO may not pay a special dividend in excess of the forecasted dividends at the end of the year unless the additional payment does not reduce the average annual rate making common equity ratio below the forecasted level of 53.45 percent.

21. WEPCO shall submit to the Commission by September 15, 2000, a proposal for volumetric charges associated with the new natural gas balancing tiers established herein.

22. WEPCO's tariffs shall be revised to reflect the fact that system-wide constraint days on the natural gas system can be called by the utility only if a physical problem exists or is likely.

23. WEPCO shall submit to the administrator of the Natural Gas Division of the Commission by October 1, 2000, a proposal for pricing natural gas in the cashout mechanism in a manner consistent with the Commission's decision herein, and the administrator is delegated the authority to approve the proposal.

24. WEPCO shall organize and form an industry workgroup whose objective it is to implement by April 1, 2001, a more workable natural gas super-pooling tariff.

25. WEPCO shall submit to the Commission staff by September 15, 2000, its study on the feasibility of allowing transporters to deliver gas in kind to replace lost and unaccounted for gas.

26. WEPCO shall, reduce its deadline for transporter natural gas nominations as soon as feasible, to no more than 1.5 hours for the initial nomination and 1.0 hour for the intra-day nominations.

Dated at Madison, Wisconsin, \_\_\_\_\_

By the Commission:

\_\_\_\_\_  
Lynda L. Dorr  
Secretary to the Commission

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See attached Notice of Appeal Rights

Notice of Appeal Rights

Notice is hereby given that a person aggrieved by the foregoing decision has the right to file a petition for judicial review as provided in Wis. Stat. § 227.53. The petition must be filed within 30 days after the date of mailing of this decision. That date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

Notice is further given that, if the foregoing decision is an order following a proceeding which is a contested case as defined in Wis. Stat. § 227.01(3), a person aggrieved by the order has the further right to file one petition for rehearing as provided in Wis. Stat. § 227.49. The petition must be filed within 20 days of the date of mailing of this decision.

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

This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

Revised 9/28/98

APPENDIX A  
(CONTESTED)

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

Public Service Commission of Wisconsin  
*(Not a party but must be served)*  
610 N. Whitney Way  
P.O. Box 7854  
Madison, WI 53707-7854

WISCONSIN ELECTRIC POWER COMPANY

by  
Mr. Larry J. Martin, Attorney  
Quarles and Brady  
411 East Wisconsin Avenue  
Milwaukee, WI 53202

IBEW, LOCAL UNION 2150

by  
Mr. Timm A. Driscoll  
Business Manager  
N8 W22520 Johnson Drive, Unit H  
Waukesha, WI 53186

SUPERIOR WATER, LIGHT AND POWER COMPANY

by  
Mr. Robert E. Evered  
2915 Hill Avenue  
P.O. Box 519  
Superior, WI 54880

WISCONSIN PAPER COUNCIL

by  
Mr. Earl Gustafson  
Energy/Projects Manager  
250 North Green Bay Road  
P.O. Box 718  
Neenah, WI 54957-0718

CITIZENS' UTILITY BOARD

by

Ms. Mary Wright, Attorney  
Cullen, West, Pines & Bach  
122 West Washington Avenue, Suite 900  
Madison, WI 53703

WISCONSIN INDUSTRIAL ENERGY GROUP (WIEG)

by

Ms. Linda M. Clifford  
Mr. Richard L. Olson  
LaFollette, Godfrey & Kahn, S.C.  
P.O. Box 2719  
Madison, WI 53701-2719

ENERGY SOLUTIONS, INC.

by

Ms. Valerie Kelm  
2386 Dahlk Circle  
Verona, WI 53593

WPS ENERGY SERVICE, INC.

by

Mr. Chris Matthiesen  
Director of Consulting  
677 Baeten Road  
Green Bay, WI 54304

WISCONSIN END-USER GAS AND ELECTRIC ASSOCIATION (WEUGEA)

by

Ms. Darcy Fabrizius  
P.O. Box 2226  
Waukesha, WI 53187-2226

WICOR ENERGY

by

Ms. Mary Wolter  
Operations and Risk Manager  
306 North Milwaukee Street  
Milwaukee, WI 53202

WISCONSIN PUBLIC SERVICE CORPORATION

by

Mr. Bradley D. Jackson, Attorney  
Foley and Lardner  
150 East Gilman Street  
P.O. Box 1497  
Madison, WI 53701-1497

HIGH SCHOOLS OF THE CATHOLIC ARCHDIOCESE  
OF MILWAUKEE

by

Mr. George E. Wennerlyn  
1549 Grosse Point Drive  
Middleton, WI 53562

MADISON GAS AND ELECTRIC COMPANY

by

Mr. Jeffrey C. Newman, Treasurer  
133 South Blair Street, P.O. Box 1231  
Madison, WI 53701-1231

RELIANT ENERGY RETAIL, INC.

by

Mr. Douglas C. Stark  
800 LaSalle Avenue, Suite 2230  
Minneapolis, MN 55402-2033

NORTHERN STATES POWER COMPANY

by

Mr. John D. Wilson, Attorney  
P.O. Box 8  
Eau Claire, WI 54702-0008

WISCONSIN PROPANE GAS ASSOCIATION

by

Mr. John V. McCoy, Attorney  
Bode, Carroll, McCoy, Hoefle & Mihal, S.C.  
20700 Swenson Drive, Suite 250  
Waukesha, WI 53186

WISCONSIN ELECTRIC POWER COMPANY  
STEP ONE AND STEP TWO REVENUE ALLOCATIONS  
AUTHORIZED ELECTRIC RATES

Rate Class	Present Revenue	STEP 1 Revenue	% Increase From Current Revenue	STEP 2 Revenue	% Increase From Step 1 Revenue	% Increase From Current Revenue
RESIDENTIAL AND FARM						
RG-1 RESIDENTIAL	\$508,749,924	\$526,091,181	3.41%	\$535,401,461	1.77%	5.24%
RG-2 RESIDENTIAL (TOU)	\$33,844,537	\$34,966,230	3.31%	\$35,719,465	2.15%	5.54%
FG-1 FARM	\$19,608,887	\$20,274,932	3.40%	\$20,635,556	1.78%	5.24%
GL-1 RESIDENTIAL AREA LIGHTING	\$631,437	\$653,910	3.56%	\$661,551	1.17%	4.77%
GL-1 FARM AREA LIGHTING	\$47,944	\$49,688	3.64%	\$50,211	1.05%	4.73%
<b>RESIDENTIAL AND FARM</b>	<b>\$562,882,729</b>	<b>\$582,035,941</b>	<b>3.40%</b>	<b>\$592,468,244</b>	<b>1.79%</b>	<b>5.26%</b>
GENERAL SECONDARY						
CG-1 GENERAL SECONDARY	\$180,357,201	\$186,445,363	3.38%	\$189,547,350	1.66%	5.10%
CG-2 GEN. SECONDARY - DEMAND	\$49,684,332	\$51,323,000	3.30%	\$52,179,309	1.67%	5.02%
CG-3 GEN. SEC. - DEMAND/TOU	\$261,825,263	\$270,375,975	3.27%	\$275,487,843	1.89%	5.22%
CG-6 GEN. SECONDARY - TOU	\$13,033,902	\$13,453,400	3.22%	\$13,750,796	2.21%	5.50%
CG-3C GEN. SEC. EXP. CURT. (TOU)	\$484,056	\$501,137	3.53%	\$510,550	1.88%	5.47%
CG-3A GEN. SEC. EXP. CURT. (TOU)	\$1,806,785	\$1,866,829	3.32%	\$1,901,892	1.88%	5.26%
GL-1 SECONDARY AREA LIGHTING	\$2,823,746	\$2,918,729	3.36%	\$2,956,177	1.28%	4.69%
<b>GENERAL SECONDARY</b>	<b>\$510,015,285</b>	<b>\$526,884,432</b>	<b>3.31%</b>	<b>\$536,333,916</b>	<b>1.79%</b>	<b>5.16%</b>
GENERAL PRIMARY						
CP-1 GENERAL PRIMARY TOU	\$331,931,724	\$331,955,009	0.01%	\$338,289,482	1.91%	1.92%
CP-2V GEN. PRIM. VAR. INTER. TOU	\$0	\$0	NA	\$0	NA	NA
CP-2M GEN. PRIM. INTER. TOU	\$18,725,022	\$18,724,886	0.00%	\$19,061,009	1.80%	1.79%
CP-3 GEN. PRIM. CURT. TOU	\$19,320,856	\$19,318,997	-0.01%	\$19,755,254	2.26%	2.25%
CP-3A GEN. PRIM. CURT. TOU	\$14,557,476	\$14,559,435	0.01%	\$14,839,427	1.92%	1.94%
<b>GENERAL PRIMARY</b>	<b>\$384,535,078</b>	<b>\$384,558,328</b>	<b>0.01%</b>	<b>\$391,945,172</b>	<b>1.92%</b>	<b>1.93%</b>
STREET LIGHTING AND OTHER						
MS-1 HIGHWAY LIGHTING	\$690,330	\$713,522	3.36%	\$725,534	1.68%	5.10%
MS-2 INCAND. STREET LIGHTING	\$2,104,737	\$2,173,906	3.29%	\$2,213,432	1.82%	5.16%
MS-3 MERC. & SOD. STREET LIGHT.	\$6,934,146	\$7,169,924	3.40%	\$7,316,782	2.05%	5.52%
MS-4 ORN. STREET LIGHTING	\$927,980	\$954,609	2.87%	\$954,609	0.00%	2.87%
St-1 14 HR ON-PEAK STR. LIGHTING	\$2,982,609	\$3,087,219	3.51%	\$3,104,544	0.56%	4.09%
CG-6 SMALL GEN. SEC. (TOU)	\$655,056	\$676,293	3.24%	\$694,807	2.74%	6.07%
AL-1 MERCURY ALLEY LIGHTING	\$335,715	\$347,231	3.43%	\$365,122	5.15%	8.76%
MG-1 MUNICIPAL SIREN SERVICE	\$3,726	\$3,888	4.35%	\$4,050	4.17%	8.70%
<b>STREET LIGHTING &amp; OTHER</b>	<b>\$14,634,299</b>	<b>\$15,126,592</b>	<b>3.36%</b>	<b>\$15,378,879</b>	<b>1.67%</b>	<b>5.09%</b>
<b>TOTAL ALL GROUPS</b>	<b>\$1,472,067,391</b>	<b>\$1,508,605,293</b>	<b>2.48%</b>	<b>\$1,536,126,211</b>	<b>1.82%</b>	<b>4.35%</b>

## WISCONSIN ELECTRIC POWER COMPANY

## ELECTRIC RATES

Rate Class	Present Rate	STEP 1 RATE	STEP 2 RATE
<b>RG-1 RESIDENTIAL</b>			
Facilities Charge			
Single phase	\$5.65	\$5.85	\$5.95
Three phase	\$11.30	\$11.70	\$12.00
Excess meter	\$1.00	\$1.00	\$1.00
Energy Charge Regular, \$/kWh	\$0.0708	\$0.0732	\$0.0745
100 % Green Rate, \$kWh	\$0.0912	\$0.0936	\$0.0949
50 % Green Rate, \$kWh	\$0.0810	\$0.0834	\$0.0847
25 % Green Rate, \$kWh	\$0.0759	\$0.0783	\$0.0796
<b>RG-2 RESIDENTIAL (TOU)</b>			
Facilities Charge			
Single phase	\$8.50	\$8.85	\$8.90
Three phase	\$14.00	\$14.45	\$14.50
Excess meter	\$2.50	\$2.50	\$2.50
Energy On-peak	\$0.1379	\$0.1423	\$0.1444
Energy Off-peak	\$0.0244	\$0.0252	\$0.0263
<b>FG-1 FARM</b>			
Facilities Charge			
Single phase	\$5.65	\$5.85	\$5.95
Three phase	\$11.30	\$11.70	\$12.00
Excess meter	\$1.00	\$1.00	\$1.00
Energy Charge	\$0.0708	\$0.0732	\$0.0745
<b>CG-1 GENERAL SECONDARY</b>			
Facilities Charge			
Single phase	\$6.60	\$6.80	\$6.80
Three phase	\$21.00	\$21.70	\$21.70
Excess Meter	\$1.00	\$1.00	\$1.00
Energy Charge	\$0.0708	\$0.0732	\$0.0745
100 % Green Rate, \$kWh	\$0.0912	\$0.0936	\$0.0949
50 % Green Rate, \$kWh	\$0.0810	\$0.0834	\$0.0847
25 % Green Rate, \$kWh	\$0.0759	\$0.0783	\$0.0796
Primary Discount	(3.00%)	(3.00%)	0.00%

Rate Class	Present Rate	STEP 1 RATE	STEP 2 RATE
<b>CG-2 GENERAL SECONDARY - DEMAND</b>			
Facilities Charge			
Single phase	\$45.00	\$46.50	\$46.50
Three phase	\$45.00	\$46.50	\$46.50
Excess meter	\$4.00	\$4.00	\$4.00
Energy (1-phase)	\$0.0537	\$0.0555	\$0.0562
Energy (3-phase)	\$0.0537	\$0.0555	\$0.0562
Demand: Regular kW	\$4.50	\$4.64	\$4.80
Base Revenue	\$2.25	\$2.32	\$2.40
Fuel Revenue	\$2.25	\$2.32	\$2.40
Primary Discount	(3.00%)	(3.00%)	(3.00%)
<b>CG-3 GENERAL SECONDARY - DEMAND/TOU</b>			
Facilities Charge	\$45.00	\$46.50	\$46.50
Excess meter	\$4.00	\$4.00	\$4.00
Demand Charges			
Regular	\$9.29	\$9.60	\$9.60
Minimum	\$3.66	\$3.78	\$3.78
Adjusted	\$5.63	\$5.82	\$5.82
Minimum per Month	\$120.00	\$120.00	\$120.00
Customer Demand Charge	\$0.68	\$0.70	\$0.70
Energy On-peak	\$0.0375	\$0.0387	\$0.0398
Energy Off-peak	\$0.0244	\$0.0252	\$0.0263
Prim Disc -Demand	(2.50%)	(2.50%)	(2.50%)
Prim Disc -Energy	(3.00%)	(3.00%)	(3.00%)
<b>CG-3C GENERAL SECONDARY EXPERIMENTAL CURTAILABLE (TOU)</b>			
Facilities Charge	\$100.00	\$103.00	\$104.00
Demand Charges			
Regular	\$9.29	\$9.60	\$9.60
Minimum	\$3.66	\$3.78	\$3.78
Adjusted	\$5.63	\$5.82	\$5.82
Customer Demand Charge	\$0.68	\$0.70	\$0.70
Curt. Credit	(\$0.0178)	(\$0.0178)	(\$0.0178)
Energy On-peak	\$0.0375	\$0.0387	\$0.0398
Energy Off-peak	\$0.0244	\$0.0252	\$0.0263

Rate Class	Present Rate	STEP 1 RATE	STEP 2 RATE
<b>CG-3A GENERAL SECONDARY EXPERIMENTAL</b>			
Facilities Charge	\$100.00	\$103.00	\$104.00
Demand Charges			
Regular	\$9.29	\$9.60	\$9.60
Minimum	\$3.66	\$3.78	\$3.78
Adjusted	\$5.63	\$5.82	\$5.82
Customer Demand Charge	\$0.68	\$0.70	\$0.70
Energy On-peak	\$0.0375	\$0.0387	\$0.0398
Energy Off-peak	\$0.0244	\$0.0252	\$0.0263
<b>CG-6 GENERAL SECONDARY – TOU</b>			
Facilities Charge			
Single phase	\$10.00	\$10.35	\$10.50
Three phase	\$23.50	\$24.30	\$24.50
Excess meter	\$3.00	\$3.00	\$3.00
Energy On-peak	\$0.1379	\$0.1423	\$0.1444
Energy Off-peak	\$0.0244	\$0.0252	\$0.0263
<b>CP-1 GENERAL PRIMARY</b>			
Low Voltage <12.5 kV			
Facilities Charge	\$525.00	\$525.00	\$525.00
Demand Charge	\$8.42	\$8.50	\$8.56
Customer Demand Charge	\$0.68	\$0.75	\$0.80
Energy On-peak	\$0.0337	\$0.0335	\$0.0341
Energy Off-peak	\$0.0207	\$0.0204	\$0.0210
CP-2 Interruptible Credit			
Hours of Use Credit	(\$0.0175)	(\$0.0175)	(\$0.0175)
CP-3 Curtailable Hours			
of Use Credit	(\$0.0168)	(\$0.0168)	(\$0.0168)
High Voltage 138kV> >12.5 kV			
Facilities Charge	\$525.00	\$525.00	\$525.00
Demand Charge	\$8.24	\$8.30	\$8.36
Customer Demand Charge	\$0.65	\$0.71	\$0.76
Energy On-peak	\$0.0327	\$0.0325	\$0.0331
Energy Off-peak	\$0.0203	\$0.0200	\$0.0206
CP-2 Interruptible Credit			
Hours of Use Credit	(\$0.0170)	(\$0.0170)	(\$0.0170)
CP-3 Curtailable Hours			
Of Use Credit	(\$0.0162)	(\$0.0162)	(\$0.0162)

Rate Class	Present Rate	STEP 1 RATE	STEP 2 RATE
<b>High Voltage 138 kV</b>			
Facilities Charge	\$525.00	\$525.00	\$525.00
Demand Charge	\$8.03	\$8.10	\$8.16
Customer Demand Charge	\$0.63	\$0.67	\$0.72
Energy On-peak	\$0.0320	\$0.0318	\$0.0324
Energy Off-peak	\$0.0187	\$0.0184	\$0.0190
CP-2 Interruptible Credit			
Hours of Use Credit	(\$0.0166)	(\$0.0166)	(\$0.0166)
CP-3 Curtailable Hours			
of Use Credit	(\$0.0157)	(\$0.0157)	(\$0.0157)
<b>CP-2M GENERAL PRIMARY INTERRUPTIBLE TOU</b>			
Facilities Charge	\$775.00	\$800.00	\$800.00
Demand Charge	\$3.66	\$3.72	\$3.78
Customer Demand Charge	\$0.65	\$0.71	\$0.76
Energy On-peak	\$0.0279	\$0.0276	\$0.0279
Energy Off-peak	\$0.0172	\$0.0169	\$0.0172
<b>GL-1 AREA LIGHTING</b>			
175 Watt MV	\$7.90	\$8.15	\$8.25
400 Watt MV	\$12.20	\$12.60	\$12.70
700 Watt MV	\$18.95	\$19.60	\$19.70
50 Watt HPS	\$6.05	\$6.25	\$6.35
70 Watt HPS	\$6.50	\$6.65	\$6.85
100 Watt HPS	\$7.20	\$7.50	\$7.55
150 Watt HPS	\$8.20	\$8.50	\$8.65
200 Watt HPS	\$9.50	\$9.80	\$10.00
250 Watt HPS	\$10.25	\$10.60	\$10.75
400 Watt HPS	\$15.00	\$15.50	\$15.70
70 Watt HPS Flood	\$8.25	\$8.55	\$8.65
100 Watt HPS Flood	\$8.85	\$9.15	\$9.25
150 Watt HPS Flood	\$9.85	\$10.20	\$10.30
200 Watt HPS Flood	\$11.00	\$11.35	\$11.50
250 Watt HPS Flood	\$12.00	\$12.40	\$12.55
400 Watt HPS Flood	\$16.50	\$17.05	\$17.20
175 Metal Halide	\$10.25	\$10.60	\$10.70
250 Metal Halide	\$12.00	\$12.40	\$12.55
400 Metal Halide	\$16.50	\$17.05	\$17.20
1,000 Metal Halide	\$27.50	\$28.40	\$28.65
Poles	\$1.55	\$1.60	\$1.60
Spans	\$0.50	\$0.50	\$0.50

Rate Class	Present Rate	STEP 1 RATE	STEP 2 RATE
<b>MS-1 HIGHWAY LIGHTING</b>			
Facilities Charge			
Single phase	\$6.60	\$6.80	\$6.80
Three phase	\$21.00	\$21.70	\$21.70
Flashers			
75 Watts or less	\$2.25	\$2.30	\$2.50
>75 Watts	\$3.65	\$3.80	\$4.00
Energy Charge	\$0.0708	\$0.0732	\$0.0745
<b>MS-2 INCANDESCENT STREET LIGHTING</b>			
Facilities Charge	\$0.00	\$0.00	\$0.00
Energy Charge	\$0.0639	\$0.0660	\$0.0672
<b>ST-1 14 HOUR ON-PEAK STREET LIGHTING</b>			
Facilities Charge			
Single phase	\$10.00	\$10.35	\$10.50
Three phase	\$23.50	\$24.30	\$24.50
Energy On-peak	\$0.1344	\$0.1388	\$0.1392
Energy Off-peak	\$0.0240	\$0.0249	\$0.0251
<b>MS-3 MERCURY &amp; SODIUM STREET LIGHTING</b>			
50 Watt HPS	\$7.35	\$7.65	\$7.90
70 Watt HPS	\$8.00	\$8.25	\$8.35
100 Watt HPS	\$9.00	\$9.30	\$9.50
150 Watt HPS	\$10.00	\$10.35	\$10.60
175 Watt HPS	\$10.60	\$10.95	\$11.25
200 Watt HPS	\$11.40	\$11.80	\$12.00
250 Watt HPS	\$12.50	\$12.90	\$13.10
400 Watt HPS	\$16.00	\$16.50	\$16.75
<b>MS-4 ORNAMENTAL STREET LIGHTING</b>			
50 Watt HPS	\$1.75	\$2.10	\$2.10
70 Watt HPS	\$2.00	\$2.35	\$2.35
100 Watt HPS	\$3.05	\$3.40	\$3.40
150 Watt HPS	\$4.20	\$4.50	\$4.50
175 Watt HPS	\$4.80	\$5.20	\$5.20
200 Watt HPS	\$5.20	\$5.75	\$5.75
250 Watt HPS	\$6.50	\$7.00	\$7.00
400 Watt HPS	\$10.35	\$10.85	\$10.85
1,000 Watt HPS	\$22.75	\$23.75	\$23.75
Facilities Charge "A"	1.90%	1.90%	1.90%
Facilities Charge "B"	0.50%	0.50%	0.50%

Rate Class	Present Rate	STEP 1 RATE	STEP 2 RATE
<b>AL-1 MERCURY ALLEY LIGHTING</b>			
100 Watt MV	\$4.05	\$4.20	\$4.35
175 Watt MV	\$6.15	\$6.35	\$6.50
50 Watt HPS	\$2.45	\$2.55	\$2.75
70 Watt HPS	\$2.95	\$3.05	\$3.20
100 Watt HPS	\$4.00	\$4.15	\$4.35
<b>MG-1 MUNICIPAL SIREN SERVICE</b>			
Warning Sirens	\$2.30	\$2.40	\$2.50
<b>CP-4 GENERAL PRIMARY STANDBY SERVICE</b>			
Reserved Demand per KW			
Less Than 12.4 KV	\$1.32	\$1.32	\$1.32
More than > 13.2 KV	\$1.10	\$1.10	\$1.10
More Than 138 KV	\$0.89	\$0.89	\$0.89
Standby Demand per KW per Hr	\$0.06	\$0.06	\$0.06
<b>COGS-1 STANDARD BUY-BACK RATE</b>			
Facilities Charge			
Non-Demand Metered	\$1.25	\$1.25	\$1.25
Demand Metered	\$3.50	\$3.50	\$3.50
Transmission Voltage			
On-Peak	\$0.0430	\$0.0430	\$0.0430
Off-Peak	\$0.0180	\$0.0180	\$0.0180
Primary Voltage			
On-Peak	\$0.0454	\$0.0454	\$0.0454
Off-Peak	\$0.0188	\$0.0188	\$0.0188
Secondary Voltage			
On-Peak	\$0.0464	\$0.0464	\$0.0464
Off-Peak	\$0.0193	\$0.0193	\$0.0193

**WISCONSIN ELECTRIC POWER COMPANY -GAS OPERATIONS  
DOCKET 6630-UR-111**

	<b>Fixed Dist</b>	<b>Fixed Enhanced Other</b>	<b>Fixed Transport Admin</b>	<b>Vol. Dist Margin</b>	<b>Vol. Comp. Supply</b>	<b>Vol. Balancing</b>	<b>Vol. Peak-Day Backup</b>	<b>Vol. Peak Demand</b>	<b>Vol. Annual Demand</b>	<b>Vol. Commodity</b>	<b>Vol. Surch.</b>	<b>Lost and Unaccount. For</b>
Residential Rg-1	\$5.00	\$0.85	\$0.00	\$0.1696	\$0.0208	\$0.0013	\$0.0022	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-1	\$8.00	\$1.45	\$0.00	\$0.1604	\$0.0158	\$0.0013	\$0.0015	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-2	\$25.00	\$1.45	\$0.00	\$0.1147	\$0.0111	\$0.0013	\$0.0012	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-3	\$75.00	\$1.45	\$0.00	\$0.0895	\$0.0088	\$0.0013	\$0.0008	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-4	\$300.00	\$0.50	\$0.00	\$0.0604	\$0.0047	\$0.0013	\$0.0005	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-5	\$650.00	\$0.50	\$0.00	\$0.0443	\$0.0035	\$0.0013	\$0.0003	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-6	\$1,200.00	\$0.50	\$0.00	\$0.0344	\$0.0025	\$0.0013	\$0.0002	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Commercial/Industrial Cg-7	\$3,000.00	\$0.50	\$0.00	\$0.0267	\$0.0015	\$0.0013	\$0.0001	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Seasonal Use Service Sg-1	\$8.00	\$1.45	\$0.00	\$0.1604	\$0.0158	\$0.0013	\$0.0015	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Seasonal Use Service Sg-2	\$25.00	\$1.45	\$0.00	\$0.1147	\$0.0111	\$0.0013	\$0.0012	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Seasonal Use Service Sg-3	\$75.00	\$1.45	\$0.00	\$0.0895	\$0.0088	\$0.0013	\$0.0008	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Seasonal Use Service Sg-4	\$300.00	\$0.50	\$0.00	\$0.0604	\$0.0047	\$0.0013	\$0.0005	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Seasonal Use Service Sg-5	\$650.00	\$0.50	\$0.00	\$0.0443	\$0.0035	\$0.0013	\$0.0003	\$0.1051	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Interruptible Ig-4	\$300.00	\$0.50	\$0.00	\$0.0604	\$0.0047	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Interruptible Ig-5	\$650.00	\$0.50	\$0.00	\$0.0443	\$0.0035	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Power Generation Pg-1	no rate											
Power Generation Pg-2	\$16,874.50	\$0.50	\$0.00	\$0.0035	\$0.0004	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Power Generation Pg-3	no rate											
Power Generation Pg-4	no rate											
Power Generation Pg-5	\$4,200.00	\$0.50	\$0.00	\$0.0150	\$0.0010	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Power Generation Pg-6	\$39,374.50	\$0.50	\$0.00	\$0.0076	\$0.0004	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Power Generation Pg-7	\$7,450.00	\$0.50	\$0.00	\$0.0192	\$0.0010	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014
Power Generation Pg-8	\$9,315.00	\$0.50	\$0.00	\$0.0200	\$0.0004	\$0.0013	\$0.0000	\$0.0000	\$0.0135	\$0.2753	\$0.0008	\$0.0014

**WISCONSIN ELECTRIC POWER COMPANY -GAS OPERATIONS  
DOCKET 6630-UR-111**

	<b>Fixed Dist</b>	<b>Fixed Enhanced Other</b>	<b>Fixed Transport Admin</b>	<b>Vol. Dist Margin</b>	<b>Vol. Comp. Supply</b>	<b>Vol. Balancing</b>	<b>Vol. Peak-Day Backup</b>	<b>Vol. Peak Demand</b>	<b>Vol. Annual Demand</b>	<b>Vol. Commodity</b>	<b>Vol. Surch.</b>	<b>Lost and Unaccount. For</b>
Residential Rt-1	\$5.00	\$0.85	\$125.00	\$0.1696	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-1	\$8.00	\$1.45	\$125.00	\$0.1604	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-2	\$25.00	\$1.45	\$125.00	\$0.1147	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-3	\$75.00	\$1.45	\$125.00	\$0.0895	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-4	\$300.00	\$0.50	\$125.00	\$0.0604	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-5	\$650.00	\$0.50	\$125.00	\$0.0443	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-6	\$1,200.00	\$0.50	\$125.00	\$0.0344	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Commercial/Industrial Ct-7	\$3,000.00	\$0.50	\$125.00	\$0.0267	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Seasonal Use Service St -1	\$8.00	\$1.45	\$125.00	\$0.1604	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Seasonal Use Service St -2	\$25.00	\$1.45	\$125.00	\$0.1147	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Seasonal Use Service St -3	\$75.00	\$1.45	\$125.00	\$0.0895	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Seasonal Use Service St -4	\$300.00	\$0.50	\$125.00	\$0.0604	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Seasonal Use Service St -5	\$650.00	\$0.50	\$125.00	\$0.0443	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Power Generation Pt-1	no rate											
Power Generation Pt-2	\$16,874.50	\$0.50	\$125.00	\$0.0035	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Power Generation Pt-3	no rate											
Power Generation Pt-4	no rate											
Power Generation Pt-5	\$4,200.00	\$0.50	\$125.00	\$0.0150	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Power Generation Pt-6	\$39,374.50	\$0.50	\$125.00	\$0.0076	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Power Generation Pt-7	\$7,450.00	\$0.50	\$125.00	\$0.0192	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
Power Generation Pt-8	\$9,315.00	\$0.50	\$125.00	\$0.0200	\$0.0000	\$0.0013	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0014
LDC Reserved Gas Supply-D1 Cost		\$0.7508per therm										
LDC Reserved Gas Supply-D2 Cost		\$0.0135per therm										

WISCONSIN ELECTRIC POWER COMPANY  
6630-UR-111  
MONTHLY FUEL COSTS ESTIMATES  
FOR YEAR ENDING DECEMBER 31, 2000

<u>Month</u>	<u>Net kWh Produced</u>	<u>Fuel Costs</u>	<u>Fuel Cost per Net kWh Produced</u>	<u>Cumulative Cost Per kWh</u>
January	2,637,276,000	\$32,945,287	\$0.01249	\$0.01249
February	2,369,374,000	29,581,043	0.01248	0.01249
March	2,518,648,000	32,276,769	0.01282	0.01260
April	2,346,320,000	30,860,591	0.01315	0.01273
May	2,420,563,000	29,374,703	0.01214	0.01261
June	2,596,153,000	31,360,099	0.01208	0.01252
July	2,757,279,000	33,536,580	0.01216	0.01246
August	2,807,047,000	36,148,175	0.01288	0.01252
September	2,491,245,000	29,164,482	0.01171	0.01243
October	2,506,986,000	39,715,944	0.01584	0.01277
November	2,404,776,000	30,821,466	0.01282	0.01277
December	2,619,907,000	33,001,686	0.01260	0.01276
Total	<u>30,475,574,000</u>	<u>\$388,786,825</u>	<u>\$0.01276</u>	<u>\$0.01276</u>