Date Mailed
December 22, 2004

BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates — 3270-UR-113

FINAL DECISION

This is the final decision regarding the application of Madison Gas and Electric Company (MGE or Applicant) for authority to change electric and natural gas rates on January 1, 2005.

Final overall rate changes are authorized consisting of a $27,387,000 annual rate increase for electric utility operations, a 10.36 percent increase; and a $4,238,000 annual rate decrease for natural gas utility operations, a 1.83 percent decrease, for the test year ending December 31, 2005. The electric increase is larger than requested by MGE because the Commission based its gas-fired generation and purchased power costs on a more current NYMEX natural gas futures price, which added approximately $9 million to the electric revenue requirement.

Introduction

On May 5, 2004, MGE filed an application with the Commission requesting authority to increase its electric utility rates by $22,345,000, an 8.47 percent increase, and to decrease its natural gas utility rates by $1,942,000, a 0.94 percent decrease, to be effective January 1, 2005.

On August 9, 2004, a prehearing conference was held to determine the issues that would be addressed in this docket and to establish a schedule for the hearing. Pursuant to due notice, a technical hearing was held on October 20, 2004. Also on October 20, 2004, a hearing was held for public comment.

The Commission considered this matter at its open meeting on December 7, 2004.

The parties for purposes of review under Wis. Stat. §§ 227.47 and 227.53 are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. It is reasonable in this proceeding to accept MGE's offer to forego an additional fuel cost increase of approximately $6.8 million by not updating fuel costs for the impact of the NYMEX strip prices as of November 15, 2004, but instead to use the NYMEX strip prices from July 15, 2004, which were the NYMEX strip prices contained in Commission staff's proposed revenue requirement.

2. Fuel cost adjustments that increase test year fuel costs by $12,687,000 from MGE's filed level are reasonable.

3. It is reasonable to incorporate costs and revenues from financial transmission rights into monitored fuel costs.

4. It is reasonable to extend MGE's Electric Risk Management Plan through the end of 2005.

5. A test year fuel cost of $124,224,000 is reasonable.

6. A test year fuel rules monitoring level of fuel costs of $102,376,863 is reasonable.

7. It is reasonable to continue monitoring the fuel costs using the following ranges: plus or minus 10 percent monthly; cumulative monthly ranges of plus or minus 10 percent for the first month, plus or minus 6 percent for 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.

8. It is reasonable for MGE to record a regulatory asset in lieu of the debit to Other Comprehensive Income (OCI) associated with recording the additional minimum pension liability. It is also reasonable to require MGE to file a pension funding plan as described in the opinion section of this order by April 1, 2005.

9. It is reasonable to reduce employee pension and benefit costs by $505,000 resulting from MGE changing an insurance provider for one of its medical plans.

10. It is reasonable to reduce employee pension and benefit costs by $1,050,000 resulting from updating FAS 106 postretirement medical costs due to the Medicare Prescription Drug Improvement and Modernization Act of 2003.

11. A ten-year period beginning on the date the facility lease commences is a reasonable time frame for amortizing MGE's payments to MGE Power West Campus, LLC, which the Commission authorized deferred accounting treatment for in docket 3270-GF-105.

12. It is reasonable to authorize escrow accounting treatment for the West Campus Cogeneration Facility (WCCF) facility lease payments through December 31, 2005. The level of facility lease payment costs included in the test year is $10,109,752.

13. Based on the order in docket 05-EI-129, the five-year phase-in period for which escrow accounting was approved for American Transmission Company, LLC (ATC)-related transmission expenses goes through December 31, 2005. Therefore, no further approval for MGE to continue escrow accounting through the 2005 test year for those ATC-related transmission expenses that are currently being escrowed is required in this proceeding.

14. The level of ATC-related transmission expenses recoverable in rates for the test year is $16,020,537. This level consists of the ATC-related transmission expense budget of

$15,736,537 plus an escrow adjustment of $284,000, which represents the amortization of the projected overspent escrow balance at December 31, 2004, over a two-year period.

15. It is reasonable to authorize MGE to defer the net revenue requirement impact resulting from any settlement MGE may receive pertaining to a claim filed by Wisconsin Public Service Corporation (WPSC) for damages over a dispute relating to the storage of spent nuclear fuel.

16. It is reasonable to authorize MGE to defer the revenue requirement impacts associated with the American Jobs Creation Act of 2004 until such time that the impacts can be reflected in a future rate proceeding.

17. The advertising expenses included in the electric and gas utility revenue requirements provide direct and substantial benefits to ratepayers.

18. It is appropriate for MGE to work with Commission staff to develop measures of success for its 2005 customer service conservation activities, using 2004 measures of success as the starting point.

19. A reasonable level of expensed conservation costs recoverable in rates for the test year is $2,841,154 for electric utility operations and $2,137,956 for natural gas utility operations. The level for electric operations consists of the conservation budget of $2,791,154 plus an escrow adjustment of $50,000, which represents the amortization of the projected overspent escrow balance at December 31, 2004, over a two-year period. The level for natural gas operations consists of the conservation budget of $2,237,956 less an escrow adjustment of $100,000, which represents the amortization of the underspent balance at December 31, 2004, over a two-year period.

20. It is reasonable to include all uncontested Commission staff adjustments to MGE’s filed operating income statements and average net investment rate bases.

21. At present rates, the estimated electric utility net operating income for the test year is $13,495,000. The estimated net operating income applicable to gas utility operations for the test year at present rates is $12,962,000.

22. The estimated average net investment rate base applicable to electric utility operations for the test year is $301,386,000. The average net investment rate base for natural gas utility operations is $104,839,000.

23. The pro forma rate of return on average net investment rate base at present rates for electric utility operations for the test year is 4.48 percent. For natural gas utility operations the pro forma rate of return at present rates for the test year is 12.36 percent.

24. A reasonable estimate of the cost of the short-term borrowing through commercial paper for the test year is 3.00 percent.

25. A reasonable average cost of long-term embedded debt is 6.44 percent.

26. It is reasonable to require MGE to submit a ten-year financial forecast in its next rate proceeding.

27. A reasonable utility capital structure for ratemaking for the test year consists of 57.64 percent common equity, 37.29 percent long-term debt, and 5.07 percent short-term debt.

28. A long-term range of 55 to 60 percent for MGE’s common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

29. For purposes of this proceeding, a reasonable financial capital structure for the test year consists of 57.20 percent common equity, 34.65 percent long-term debt, 3.40 percent debt-equivalent off-balance sheet obligations, and 4.75 percent short-term debt.

30. It is reasonable for the Commission to base MGE's dividend restrictions established in docket 9407-YO-100 on the determinations made by the Commission in this proceeding relating to MGE's financial capital structure. It is reasonable to limit the amount of dividends that MGE can pay to its parent holding company to the amount used to calculate the amount of equity in the utility's capital structure during the test year if its common equity ratio, on a financial basis, is below the 55 to 60 percent range established by the Commission. It is reasonable to allow MGE to pay dividends to its parent holding company in excess of this amount if MGE Energy issues shares through its dividend reinvestment plan greater than the number used in the forecast, and the proceeds of these shares are invested in MGE.

31. It is not necessary for MGE to analyze the effect of issuing preferred stock.

32. A reasonable return on common stock equity is 11.50 percent.

33. A reasonable weighted average composite cost of capital is 9.18 percent.

34. It is reasonable for MGE to earn a current return on 50 percent of test year construction work in progress (CWIP), and that the remaining CWIP accrue allowance for funds used during construction (AFUDC) at the adjusted weighted cost of capital.

35. A reasonable test year rate of return on average net investment rate base for electric utility operations is 9.92 percent. For gas utility operations a reasonable test year rate of return on average net investment rate base is 9.94 percent.

36. MGE's operating revenue requirement for electric utility operations for the test year to produce a return of 9.92 percent on average net investment rate base is $299,222,000. The operating revenue requirement for natural gas utility operations to produce a return of 9.94 percent on average net investment rate base is $228,143,000.

37. Presently authorized rates for electric utility operations will produce operating revenues of $271,835,000, which results in an annual revenue deficiency of $27,387,000. Present electric rates of MGE are unreasonable because the revenues produced by these rates are inadequate.

38. Presently authorized rates for gas utility operations will produce operating revenues of $232,381,000, which results in an annual excess of $4,238,000. Present gas rates of MGE are unreasonable because they produce excess revenue.

39. To provide operating revenues to cover total cost of service for the test year, an increase in revenue applicable to electric utility operations in the amount of $27,387,000 is required. For gas utility operations, a decrease in the amount of $4,238,000 is required. The increase in electric utility operations and the decrease in gas utility operations are reasonable.

40. It is reasonable to consider all of the cost-of-service information presented for purposes of determining electric revenue allocation and setting electric rates.

41. It is reasonable to approve rates for electric service for the test year to achieve customer class changes in revenue as shown in Appendix B.

42. It is reasonable to authorize the natural gas rates shown in Appendix C.

43. It is reasonable to approve the new Large Annual Use Gas Sales Service tariff.

44. It is reasonable to approve the new Steam and Power Generation Distribution Service tariff, which would offer firm distribution service to its customers.

45. It is reasonable to include an Administrative Charge in the Daily Balancing Service cashout provision for overtake imbalances. Additionally, it is reasonable to make clarifying language changes in the balancing service tariff.

46. The Commission is persuaded by the evidence that, on the whole, Viroqua customers will see a benefit from the proposed combination of the Viroqua Municipal Natural Gas Utility's and MGE's gas costs and that the combination is reasonable. Further, it is reasonable that this change shall take place and become effective November 1, 2005, to coincide with the start of the interstate natural gas pipeline gas year.

Conclusions of Law

The Commission concludes that it has jurisdiction under Wis. Stat. §§ 1.11, 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 chs. PSC 113, 116, and 134 to enter an order authorizing MGE to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C and the fuel cost treatment set forth in Appendix D, subject to the conditions specified in this order.

Opinion

Applicant and Its Business

MGE is an electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a). It is engaged in the production, transmission, distribution, and sale of electric energy to approximately 133,000 retail customers in Madison and the surrounding area in Dane County, and in the purchase, transportation, distribution, and sale of natural gas to approximately

130,000 customers in Madison and the surrounding area in Columbia, Crawford, Dane, Iowa, Juneau, Monroe and Vernon Counties. MGE is an operating subsidiary of MGE Energy, a holding company based in Madison, Wisconsin.

Income Statement

MGE, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of MGE's 2005 electric and natural gas utility operations. Significant issues pertaining to the income statement are addressed separately below.

Fuel Costs

Commission staff based its estimate of gas-fired generation and purchased power costs on more current NYMEX natural gas futures prices which increased the electric revenue requirement by approximately $9 million. In its initial brief, MGE offered to forego an additional $6.8 million of fuel costs that would have resulted from updating the NYMEX natural gas futures strip from July 15, 2004, which was the time period used by Commission staff, to November 15, 2004. The Commission considers MGE's proposal to forego the increase in fuel costs to be reasonable and does not consider this change in procedure to be precedential. MGE is not precluded from requesting that the revenue requirement impact relating to updated NYMEX prices be incorporated in future rate case proceedings. The Commission also considers Commission staff's fuel cost adjustments, which increase test year fuel costs by $12,687,000 from MGE's filed level, to be reasonable.

For purposes of this proceeding, all parties and Commission staff assumed that Midwest Independent System Operator (MISO) would commence "Day 2" operations on March 1, 2005. Under MISO Day 2 traditional transmission reservations will be replaced by financial transmission rights (FTRs). MISO Day 2 will use a system based on locational marginal pricing (LMP). When transmission constraints exist, LMP prices between pricing nodes will be different. Differences in LMPs are referred to as congestion costs. FTRs will allow transmission users, such as MGE, to use FTRs as a hedge against congestion costs.

MGE submitted Exhibit 1.15 containing its proposal for treatment of various costs and revenues associated with MISO Day 2 operations. MGE proposed escrow treatment, inclusion in base rates, and monitored fuel rules treatment depending on the characteristics of the cost or revenue involved. MGE proposed that costs and revenues associated with FTRs be incorporated into its monitored fuel costs. The Citizens' Utility Board (CUB) proposed that FTR costs and revenues be escrowed, arguing that financial transmission rights are closer to network transmission service than a variable cost or revenue. The value of an FTR depends on the differences in LMP prices between nodes on an hourly basis—therefore, it is variable in nature. The Commission considers it reasonable to include FTR costs and revenues in monitored fuel rules. MGE also requested that purchases of FTRs associated with purchases of energy outside of MISO would also be included in monitored fuel rules. The Commission considers MGE's proposal to be reasonable.

MGE requested that it's Electric Risk Management Plan (ERMP), due to expire at the end of 2004, be extended to the end of 2007. CUB argued in its briefs that the extension should only be made through the end of 2005, given the uncertainty surrounding MISO Day 2. The Commission finds it reasonable to authorize MGE to extend its ERMP through the end of 2005.

The Commission finds that a reasonable test year level of fuel costs is $124,224,000, which reflects the cost of generation, purchased energy, wheeling, and capacity less the revenues from opportunity sales of energy and capacity. The test year fuel cost divided by the test year estimate of native energy requirements of 3,434,290 MWh results in an average net fuel cost per KWh of $.03617.

Any cost for purchased capacity that is required to meet reserve requirements is excluded from monitored fuel rules and may only be adjusted in a rate case. Firm transmission associated with excluded capacity purchases, fuel and ash handling, and sulfur dioxide (SO_2) allowance costs are excluded as well. The Commission finds that a reasonable level of test year monitored fuel costs is $102,376,863. Appendix D shows the monthly fuel costs to be used for monitoring purposes.

Under Wis. Admin. Code § PSC 116.04, the Commission establishes monthly and annual ranges for monitoring fuel forecasts. The Commission finds that the following variance ranges are reasonable for monitoring MGE'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 year, plus or minus 6 percent for the second month, 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 MGE, shall continue to be used and applied, using the data in Appendix D for monitoring fuel costs.

Pension-related Other Comprehensive Income

MGE provides pension benefits to its employees under a defined-benefit pension plan and recognizes pension expense for financial accounting and reporting purposes in accordance with Statement of Financial Accounting Standard No. 87, Employers' Accounting for Pensions (SFAS No. 87). The cost of pension benefits provided to employees under a defined-benefit pension benefit plan are recognized as an expense at the time the employee provides related employment services.

SFAS No. 87 requires immediate recognition of a liability (additional minimum pension liability) when the accumulated pension obligation exceeds the fair value of plan assets, although it delays recognition of the offsetting increase in pension expense. As a result of declines in the value of pension fund assets and an increase in the accumulated pension benefit obligation due to lower interest rates used to estimate that obligation on a present value basis, a number of Wisconsin utilities have determined that their accumulated pension benefit obligation exceeds the fair value of the assets set aside to meet that obligation. Consistent with the requirements of SFAS No. 87, therefore, these utilities have recorded an additional minimum pension liability for the amount of such excess. According to SFAS No. 87, the offset to the recording of a minimum pension liability is made to an intangible asset (for the portion related to unrecognized prior service cost) and to OCI. The debit to OCI is a reduction to shareholder's equity, so the journal entry does not impact the income statement. The debit to OCI represents future expenses that will be recorded under the regular SFAS No. 87 provisions over time unless future events, such as improvements in the economy, reverse the accumulated loss position. MGE testified that the debit to OCI should be replaced with a regulatory asset. This accounting treatment is consistent with the position supported by the Financial Accounting Standards Board, the opinions of independent certified public accountants from major national accounting firms, and with the Federal Energy Regulatory Commission's (FERC) accounting guidance. It is reasonable, therefore, to record a regulatory asset in lieu of the debit to OCI associated with recording the additional minimum pension liability.

In this proceeding, the Commission noted that there is insufficient information to determine whether ratepayers are better off with a well-funded pension plan, a minimally-funded pension plan, or something in between. It is therefore reasonable to direct MGE to provide a report to the Commission describing its funding practices and rationale, including ratepayer impacts, by April 1, 2005. The funding plan to be filed by MGE should include a discussion of the various funding alternatives, including the maximum tax-deductible funding method. The discussion should include a long-term economic analysis that demonstrates why MGE's preferred funding method would be more beneficial to ratepayers than consistently funding the maximum tax-deductible amount or using any other funding alternatives. The economic analysis should include any assumptions used for determining expense and funding levels.

Employee Pensions and Benefits

In supplemental testimony, MGE indicated that it was continuing to pursue cost saving opportunities for its ratepayers. MGE stated that it had decided to pursue changing an insurance provider for one of its medical plans and wanted to reflect an estimate of the potential cost reduction in its revenue requirement. The Commission considers it reasonable to reflect this reduction in the test year. The operations and maintenance (O&M) expense impact associated with MGE changing an insurance provider reduces electric and gas employee pension and benefit costs by $323,000 and $182,000 respectively.

In rebuttal testimony, MGE indicated that Towers and Perrin, the company's actuary, provided them with an update for FAS 106 postretirement medical costs for 2005 as a result of the Medicare Prescription Drug Improvement and Modernization Act of 2003. This update resulted in cost savings for MGE in 2005. The Commission considers it reasonable to reflect these savings in the test year. The O&M expense impact reduces electric and gas employee pension and benefit costs by $672,000 and $378,000 respectively.

Appropriate Period of Time over Which to Amortize Payments to MGE Power West Campus, LLC, Which the Commission Authorized Deferred Accounting Treatment for in Docket 3270-GF-105

In docket 3270-GF-105, mailed February 2, 2004, the Commission authorized deferred accounting treatment for payments to MGE Power West Campus, LLC that are incurred on or after January 29, 2004, for carrying costs on construction expenditures at the authorized return on capital, management fees and carrying costs incurred by MGE as a result of making such payments to MGE Power West Campus, LLC prior to receiving rate recovery at 1.5 percent. In direct testimony, MGE proposed to amortize these deferred costs over a ten-year period beginning on the date the facility lease commences.

The Commission considers a ten-year period beginning on the date the facility lease commences to be a reasonable period of time over which to amortize MGE's payments to MGE Power West Campus, LLC. Commission staff has estimated the total amount of these payments to be $12,796,418. Based on an estimated commercial operation date of May 1, 2005, Commission staff has included $853,096 ($12,796,418 ÷ 120 months = $106,637 per month × 8 months) of carrying costs in the test year.

Escrow Accounting Treatment for WCCF Facility Lease Payments

There are three distinct components that comprise MGE's payments for the WCCF project. The first component is the facility lease payment which consists of the basic rent, an estimate for demolition and removal costs, and a management fee. Commission staff's estimate of the test year monthly costs for these items is $1,244,592, $15,127 and $4,000 respectively for a total of $1,263,719. The second component is the carrying costs on construction expenditures at the authorized return on capital, management fees and carrying costs incurred by MGE as a result of making payments to MGE Power West Campus, LLC prior to receiving rate recovery at 1.5 percent. As previously indicated, the Commission authorized deferred accounting treatment for these costs in docket 3270-GF-105. The third component is the ground lease payment. Commission staff's estimate of the test year monthly cost for this item is $15,117.

MGE proposed that escrow accounting treatment for the facility lease payments be utilized in 2005 if the start date of the payments, which was estimated as May 1, 2005, or the amount of the payments differs from the levels included in the test year. MGE did not propose escrow accounting treatment for the ground lease payment since the monthly amount was not material. Because of the uncertainty of the start date of commercial operation of the WCCF and because of the magnitude of the monthly lease payment, the Commission authorizes escrow accounting treatment for the facility lease payments through December 31, 2005. The level of facility lease payment costs included in the test year is $10,109,752 ($1,263,719 × 8 months).

Escrow Accounting for ATC-Related Transmission Expenses

In supplemental testimony, MGE requested continuation of escrow accounting for ATC-related transmission costs that are currently included in the escrow until such time that these costs become more stable and predictable. The costs included in the escrow are ATC network integration transmission service, reliability-related dispatch costs, FERC administrative fee, MISO cost recovery adder, and scheduling, system control and dispatch service. Based on the order in docket 05-EI-129, the five-year phase-in period for which escrow accounting was approved goes through December 31, 2005. Therefore, no further approval to continue escrow accounting is required in this proceeding.

The level of ATC-related transmission expenses recoverable in rates for the test year, is $16,020,537. This level consists of the ATC-related transmission expense budget of $15,736,537 plus an escrow adjustment of $284,000, which represents the amortization of the projected overspent escrow balance at December 31, 2004, over a two-year period.

Potential Settlement Relating to a Claim Filed by WPSC for Damages over a Dispute Relating to the Storage of Spent Nuclear Fuel

During its audit in this proceeding, Commission staff became aware that WPSC had filed a claim for damages in 2004 over a dispute relating to the storage of spent nuclear fuel. Commission staff proposed that if MGE received any settlement, MGE should defer the revenue requirement impact until a future rate proceeding when the settlement could be returned to ratepayers.

In rebuttal testimony, MGE stated that it agreed with Commission staff's proposal to defer the revenue requirement impact if it received a settlement. In addition, MGE requested that the Commission authorize deferral of any incremental costs the company would incur associated with the litigation of this claim. MGE also requested that the Commission approve the deferral request with carrying costs calculated at the overall weighted cost of capital.

The Commission authorizes MGE to defer the net revenue requirement impact resulting from any settlement MGE may receive relating to the claim filed by WPSC for damages pertaining to the storage of spent nuclear fuel until such time that the settlement can be returned to ratepayers in a future rate proceeding.

American Jobs Creation Act of 2004

At the time of the October 20, 2004, hearing in this proceeding, the American Jobs Creation Act of 2004 (ACT) had recently been passed by Congress and was headed to the President's desk for signing. Subsequent to the hearing, the President signed the ACT on October 22, 2004. While the ratepayer impact of the ACT is unknown at this time, it is expected that this ACT will create significant economic benefits to the electric utility industry.

During the hearing, MGE was asked if it knew what the revenue requirement impact of this ACT would be on its operations and MGE responded that the impacts had not yet been analyzed. Based on Examiner Whitcomb's ruling, Commission staff sent out a data request asking the company to provide the test year electric and gas revenue requirement impacts associated with this ACT. On October 29, 2004, MGE responded that since the tax regulations and IRS guidance has not yet been issued, the company is unable to determine the revenue requirement impacts of the potential reduction in 2005 taxes as a result of this ACT.

In its reply brief, MGE noted that WPSC had recently requested deferral of the cost savings that result from the ACT. MGE stated that if the Commission approved WPSC's request, the company would not object to the Commission ordering similar treatment for MGE.

At its December 7, 2004, open meeting, the Commission approved WPSC's request for deferral of the 2005 revenue requirement impacts resulting from the ACT. To be consistent with the treatment afforded WPSC, the Commission finds that MGE shall defer the revenue requirement impacts associated with this ACT until such time that the impacts can be reflected in a future rate proceeding.

Advertising

Commission staff excluded $34,000 of MGE's proposed test year advertising expenses based on its review of the company's advertising budget for calendar year 2005. The balance of applicant's advertising, as evidenced by the record in this proceeding, produces a direct and substantial benefit to ratepayers. Various portions of the applicant's advertising demonstrate energy conservation methods, demonstrate methods of reducing ratepayer costs, are required by law, or otherwise directly and substantially benefit ratepayers. Therefore, pursuant to Wis. Stat. § 196.595, except for the exclusion noted above, the Commission will allow the cost of such advertising to be recovered in rates.

Demand-side Management

Measures of Success for the Test Year

In docket 05-BU-100, the Commission determined that some measure of success is needed to ensure the customer service conservation funds spent by utilities provide a useful service to ratepayers. The Commission also determined it appropriate for Commission staff to work with each utility to develop appropriate measures of success for customer service conservation activities. MGE did not propose measures of success for its 2005 customer service conservation activities. It is appropriate for MGE to work with Commission staff to develop measures of success for 2005 using the 2004 measures of success as a starting point.

Conservation Budget and Escrow Adjustment

MGE proposed a combined electric and natural gas conservation budget of $5,029,110 ($4,719,464 direct costs). This is about $300,000 higher than the minimum spending levels required in docket 05-BU-100. The $300,000 will be used to provide a higher level of customer service conservation activities than that required in docket 05-BU-100. MGE's proposed conservation escrow budget is appropriate.

The level of expensed conservation costs recoverable in rates for the test year is $2,841,154 for electric utility operations and $2,137,956 for natural gas utility operations. The level for electric operations consists of the conservation budget of $2,791,154 plus an escrow adjustment of $50,000, which represents the amortization of the projected overspent escrow balance at December 31, 2004, over a two-year period. The level for natural gas operations consists of the conservation budget of $2,237,956 less an escrow adjustment of $100,000, which represents the amortization of the projected underspent escrow balance at December 31, 2004, over a two-year period. It is reasonable to require MGE to continue accounting for allowable conservation expenditures on an escrow basis.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this opinion, all other Commission staff adjustments to MGE's filed operating income statements are reasonable and just. Accordingly, the estimated electric and gas utility operating income statements at present rates for the test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Gas (000's)
Operating Revenues		
Sales of Electricity	$264,325	$ -
Sales for Resale	5,767	-
Sales of Gas	-	228,622
Transportation Sales	-	3,330
Other Operating Revenues	1,743	429
Total Operating Revenues	$271,835	$232,381
Operating Expenses		
Steam Power Generation Expenses	$ 88,543	$ -
Nuclear Power Generation Expenses	298	-
Other Power Generation Expenses	26,954	-
Other Power Supply Expenses	44,366	-
Manufactured Gas Production Expenses	-	94
Purchased Gas Expenses	-	172,238
Transmission Expenses	18,804	-
Distribution Expenses	10,485	6,983
Customer Accounts Expenses	5,309	4,503
Customer Service Expenses	4,117	3,295
Administrative & General Expenses	26,114	14,485
Total Operation & Maintenance Expenses	$224,990	$201,598
Depreciation and Amortization Expense	19,056	7,878
Taxes Other Than Income Taxes	10,938	3,111
Deferred Income Taxes	1,525	(124)
State Income Taxes	191	1,284
Federal Income Taxes	1,935	5,838
Investment Tax Credit	(295)	(166)
Total Operating Expenses	$258,340	$219,419
Net Operating Income	$ 13,495	$ 12,962

Summary of Average Net Investment Rate Bases

Commission staff made several adjustments to MGE's filed electric and gas utility average net investment rate bases. No party opposed these adjustments. Accordingly, the estimated electric and gas utility average net investment rate bases for the test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

		Electric (000's)	Gas (000's)
Utility Plant in Service		$626,551	$245,704
Less:	Reserve for Depreciation	272,796	136,334
Net Utility Plant		$353,755	$109,370
Add:	Fuel Inventory	6,210	-
	Stored Gas	-	15,121
	Materials and Supplies	6,109	895
Less:	Accumulated Deferred Income Taxes	63,452	19,241
	Customer Advances for Construction	1,236	1,306
Average Net Investment Rate Base		$301,386	$104,839

Pro Forma Rate of Return

The net operating income for purposes of this proceeding for the test year ending December 31, 2005, results in a rate of return on the average net investment rate base of 4.48 percent for electric utility operations and 12.36 percent for natural gas utility operations.

Cost of Short-Term Debt

MGE's test year capital structure includes approximately $23.6 million of short-term debt. It is reasonable to estimate the average cost of the short-term debt using a forecast of the average cost of commercial paper based on the average of the estimates for the test year provided by Blue Chip Financial Forecasts newsletter. This forecast is currently 3.00 percent.

Cost of Long-Term Debt

MGE has long-term debt of $ 173.5 million outstanding for the test year. It is reasonable to include the cost of this debt in the test year. The Commission determines that the cost of embedded long-term debt for the test year is 6.44 percent.

Ten-Year Financial Forecast

For the past several years, the Commission has required energy utilities to submit a ten-year financial forecast as part of their rate case filings. MGE's ten-year financial forecast provides useful information for the Commission and MGE should continue to submit such a forecast in future rate proceedings.

Regulatory Capital Structure

A reasonable utility ratemaking capital structure for the purpose of establishing just and reasonable rates for the test year consists of 57.64 percent common equity, 37.29 percent long-term debt and 5.07 percent short-term debt.

Financial Capital Structure

The Commission has found in several previous proceedings that a range of 55 percent to 60 percent is a reasonable long-term range for MGE's common equity ratio, on a financial basis. This range was not contested in this proceeding and the Commission determines that this range continues to be reasonable.

Consistent with the Commission's determinations in previous dockets, Commission staff included off-balance sheet obligations in MGE's financial capital structure. In the financial capital structure MGE proposed in its application, MGE included an off-balance sheet obligation of $17,010,000 which represents 30 percent of the net present value of the capacity payments associated with MGE's long-term purchased power agreement. Commission staff also included this amount as an off-balance sheet item in its proposed financial capital structure. It is appropriate to include this amount in the financial capital structure.

The Commission determines that $17,010,000 is a reasonable estimate of the amount of debt equivalents to be imputed into MGE's financial capital structure. Therefore, for the purposes of this proceeding, a reasonable financial capital structure for the test year consists of 57.20 percent common equity, 34.65 percent long-term debt, 3.40 percent debt-equivalent off-balance sheet obligations, and 4.75 percent short-term debt.

Dividend Restriction

MGE is a wholly-owned subsidiary of its holding company parent, MGE Energy. As such, all of MGE's dividends are paid to MGE Energy. In the order approving the formation of MGE Energy in docket 9407-YO-100, the Commission made it clear that the dividend policy of the utility should reflect the financial needs of the utility, not the holding company parent. In that order, the Commission restricted MGE from paying dividends "in excess of the typical level" to MGE Energy if the level of equity in the utility was lower than the lower end of the 55-60 percent range the Commission had established in previous rate proceedings. Since the Commission had no information on the "typical level" of dividends that had been paid by MGE, the Commission ordered the utility to file historical information on dividend growth rates.

Subsequent to the issuance of the order approving the formation of the holding company, the Commission has issued orders in the MGE rate cases preceding this case. In the orders in dockets 3270-UR-111 and 3270-UR-112, the Commission restricted the dividends that could be paid by MGE to MGE Energy to the dollar amount of dividends that had been used in the calculation of the utility's capital structure for the test year.

The Commission reiterates the guiding principle that the utility's dividend policy should reflect the financial needs of the utility, not the holding company parent. The Commission understands MGE's concern for the need to accommodate the payment of dividends that result from unanticipated investment in MGE Energy as a result of the dividend reinvestment program. However, MGE should only be responsible to pay dividends on the additional shares to the extent the proceeds are invested in MGE. Therefore, MGE may pay dividends in excess of the amount used in the forecast if it can show that dividend payments above this amount result from the issuance of shares in excess of the number forecast to be outstanding during the test year, and the proceeds have been invested in MGE, not retained by MGE Energy.

Preferred Stock

MGE does not have any preferred stock in its capital structure. In this case, the Wisconsin Industrial Energy Group (WIEG) urged the Commission to require MGE to analyze the issuance of preferred stock in order to determine if such an issuance could lower MGE's cost of capital without lowering its credit rating. The Commission determines that it is not necessary for MGE to perform such an analysis at this time.

Return on Equity

The principal factor used to determine the appropriate return on equity is the investors' required return. Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility consumers who ultimately are responsible for paying for those returns.

If the investors' required return could be measured precisely, setting the authorized return would be straightforward. Because that return cannot be measured precisely, determining the appropriate return on equity is typically one of the most contested issues in a rate proceeding such as this one.

In this proceeding, MGE has requested a return on equity for the 2005 test year of 12.0 percent. MGE's Vice President and Treasurer testified that a 12.0 percent return on equity was needed to maintain MGE's bond rating. WIEG's witness presented the results of three different models which produced estimates of the required return in the range of 9.7 percent to 11.6 percent. Commission staff proposed a range of 10.8 percent to 11.8 percent based on a Discounted Cash Flow analysis and an Interest Rate Premium analysis, and Commission staff analysis presented in the most recent WPSC rate case.

In reaching its determination as to the appropriate return on equity the Commission must balance the needs of investors with the needs of consumers. That balance is struck most reasonably in this proceeding by authorizing a return on equity capital of 11.50 percent. An 11.50 percent return should allow the applicant to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs. Commissioner Garvin dissents and would allow a 12.00 percent return on common stock equity.[1]

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:

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[1] Commissioner Garvin elected not to write a separate dissent in light of his previous Concurring Opinion of January 12, 2004, in docket 3270-UR-112. In addition, the forecasted 10-year U.S. Treasury note yield is currently greater than the actual yield at the time of the Commission decision in 3270-UR-112.

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$268,140	57.64%	11.50%	6.63%
Long-Term Debt	173,500	37.29%	6.44%	2.40%
Short-Term Debt	23,589	5.07%	3.00%	0.15%
Total Utility Capital	$465,229	100.00%		9.18%

The weighted cost of capital of 9.18 percent is reasonable for MGE for the test year. It generates an economic cost of capital of 13.62 percent and a pre-tax interest coverage ratio of 5.34 times.

Rate of Return on Rate Base

The 9.18 percent composite cost of capital must be translated into a rate of return which can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of MGE's average net investment rate base plus construction work in progress for the test year is 96.74 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 the 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. Given MGE's financing and cash flow requirements in the test year and the forecasted amount of construction activity, it is reasonable to allow a current return on 50 percent of CWIP for the test year. In addition, an adjustment is needed to reflect the tax savings of MGE's Industrial Development Revenue Bonds entirely in the electric revenue requirement.

Accordingly, the rate of return on average electric and gas net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

	Electric	Gas
Cost of Capital	9.18%	9.18%
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	96.74%	96.74%
Percent Return Requirement Applicable to Net Investment Rate Base	9.49%	9.49%
Adjustment to Return Requirement to Provide Current Return on CWIP	0.48%	0.30%
Adjustment to Reflect Tax Savings on Industrial Development Revenue Bonds	(0.05%)	0.15%
Adjusted Percent Return Requirement on Average Net Investment Rate Base	9.92%	9.94%

Revenue Requirement

On the basis of the findings in this order, a $27,387,000 increase in electric utility revenues and a $4,238,000 decrease in gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	4.48%	12.36%
Required Return on Average net Investment Rate Base	9.92%	9.94%
Earnings Deficiency (Excess Revenue) as a Percent of Average Net Investment Rate Base	5.44%	(2.42%)
Average Net Investment Rate Base (000's)	$301,386	$104,839
Amount of Earnings Deficiency (Excess Revenue) on Average Net Investment Rate Base (000's)	$ 16,395	$ (2,537)
Revenue Deficiency (Excess Revenue) to Provide for Earnings Deficiency (Excess Earnings) Plus Federal and State Income Taxes (000's)	$ 27,387	$ (4,238)

Electric Revenue Allocation and Rate Design

Both the applicant and CUB testified regarding cost-of-service issues and proposed electric revenue allocations in this docket. The Commission staff also presented an electric revenue allocation based on cost-of-service, rate comparisons and bill impact information. The Commission continues to rely on the results of electric cost-of-service studies and other information presented in this proceeding as a guide in determining revenue allocation and setting rates.

Revenue allocation in this case was determined by considering factors other than simply the cost-of-service results. These factors include customer bill impacts, marginal energy cost, and rate comparability with other utilities in Wisconsin and surrounding states. Based on the overall weighing of these factors, it is reasonable to assign the electric revenue changes as shown in Appendix B with a slightly higher than average increase to the commercial and industrial classes and a slightly lower than average increase to the residential customer classes. The individual electric rate class impacts are affected by other factors such as established rate relationships, customer bill impacts for both high and low energy use customers of all classes, and the relationship of tariff charges to marginal energy cost. The electric rates shown in Appendix B are reasonable and appropriately reflect the Commission's consideration of all of these factors.

Residential Time-of-Day Rates

CUB proposed a new and innovative residential TOD rate that required air-conditioner load control. The Commission rejected CUB's proposal, but directs MGE to investigate alternative TOD rate structures that send better price signals to customers.

Interruptible Buy-through Provision

The Commission ordered MGE, in docket 3270-UR-112, to evaluate the possibility of restructuring the Cp-1 tariff to avoid the premium contained in the existing tariff. MGE proposed changes to this buy-through provision that included billing the customer the actual buy-through price plus a 10 percent adder applied to the energy purchased during the buy-through. Linde Gas proposed an alternative mark-up of $1 to $2 per MWh because this would better reflect MGE's actual out of pocket costs. The Commission finds that a $2 per MWh mark-up on the energy MGE purchases for the Cp-1 interruptible buy-through provision is reasonable.

Buy-Back Rates

The Commission finds it reasonable to adjust MGE's parallel generation, Pg-1, buy-back rates to better reflect the utility's marginal cost of energy. The authorized parallel generation, Pg-1, buy-back rates are shown in Appendix B.

Electric Service Rules

MGE proposed several electric tariff language changes. One change includes a provision for combined metering, which would have allowed coincident demand billing. The Commission has rejected similar proposals from other private utilities, because coincident demand billing simply shifts costs to other customers and does not reduce the utility's overall costs. The Commission confirms this general policy and rejects MGE's proposed changes associated with combined metering. Commissioner Garvin dissented. The Commission approves MGE's other proposed electric tariff language changes.

Natural Gas Tariffs

Large Annual Use Gas Sales Service Tariff (LS-1)

The only customer that would be served under the new LS-1 tariff is MGE's West Campus Cogeneration Facility (WCCF), which is expected to begin operation in May 2005. The LS-1 tariff would allow the facility access to utility gas supply, as well as allow the facility to have the ability to fix the price of all or part of its gas needs, or to purchase gas on the daily market. The company's LS-1 tariff proposal was supported by CUB.

The proposed LS-1 tariff is reasonable. It provides an innovative gas supply service to WCCF, while benefiting other system supply customers. As a utility gas supply customer, WCCF would help pay for fixed gas supply reservation costs already in place to serve other customers. There is also the potential that the facility could reduce costs to other customers through more efficient use of pipeline capacity.

The tariff is fashioned in a way that minimizes the risk of negative financial impacts to other system supply customers by providing that any cost effects due to the facility's fixed price or daily market gas supply choices are borne by WCCF. The cost effects of any financial or physical instruments purchased specifically to lock in a gas price for the facility would flow directly to WCCF. The costs of any gas supply purchased on the daily market specifically for WCCF would be directly allocated to it. On days when daily gas supply is purchased during traditional trading hours for both WCCF and other system customers, the cost of this gas would be allocated based on the weighted average cost of all daily purchases for that gas day. If intraday purchases are made for both WCCF and system supply customers, the costs would be allocated based on the weighted average cost of these specific purchases. Due to the large size of the facility and its variable load, WCCF would be required to nominate its usage. The LS-1 cashout mechanism is designed to insulate other utility gas supply customers from the impacts of any monthly overtakes or undertakes in usage when compared to WCCF's nomination.

Careful recordkeeping is imperative to ensure that gas supply costs are equitably allocated between WCCF and other system sales customers. Appropriate cost allocation is also necessary to determine the monthly purchased gas cost adjustment and to calculate the results of the company's gas cost incentive mechanism. The company testified that it has processes in place to appropriately determine and allocate costs, and would keep records in a manner that could be readily reviewed by Commission staff**.**

Steam and Power Generation Distribution Service Tariff (SP-1)

MGE proposed providing distribution service to WCCF under its new SP-1 tariff. Under the company's proposal, WCCF would be allowed to contract for a chosen level of firm distribution service, with the balance of its distribution service provided on an interruptible basis. The facility would pay an interruptible distribution charge for each therm of usage, plus an additional firm capacity charge per therm per day for any elected firm distribution capacity.

Because the company stated that its distribution system has ample capacity to serve WCCF at all times, the company's proposal to offer WCCF the option to choose a level of interruptible distribution service at a discounted rate is not reasonable. Interruptible distribution service should only be offered to customers that could experience service interruptions due to limited capacity. Under these conditions, the utility has avoided the cost of building mains to peak capacity and can pass this savings on to the affected customers. Recent reinforcements to the MGE distribution system provide sufficient capacity to meet WCCF's highest needs, so the utility has not avoided any costs in providing its distribution service.

It is appropriate to offer WCCF only firm distribution service under the SP-1 tariff. At some time in the future, if the distribution system would need to be upgraded to accommodate the facility's gas usage, it would be reasonable to reevaluate the appropriateness of serving the facility with interruptible distribution capacity at a discounted rate.

Daily Balancing Service (DBS-1) Tariffs

MGE proposed including an Administrative Charge of $0.0171 per therm in the DBS-1 cashout provision for overtake imbalances. It is reasonable to include the administrative charge in the calculation of the price for overtakes to recover the company's cost of procuring gas for transporters.

MGE also proposed changes in the DBS-1 tariff language. It is appropriate to incorporate these changes, which clarify the tariff.

Natural Gas Rate Design

MGE provided a rate design based on its proposed 3.2 percent distribution service revenue decrease. Commission staff offered a rate design reflecting a 6.4 percent distribution service revenue decrease based on the results of its audit. At the level of the audited revenue requirement, the company supported Commission staff's rate design, with the exception of its proposed SP-1 rates for WCCF. For WCCF, the company proposed a revenue level of $1,300,000 based on its cost-of-service study (COSS) results. Staff proposed collecting $1,525,600 from WCCF based on the results of its two COSS, titled COSS A and COSS B.

Commission staff's proposed rate design provides a slightly larger decrease to some commercial and industrial customers than to residential customers based on its COSS results. CUB criticized staff's rate design, indicating that the proposed rates rely more on the results of COSS A than COSS B. CUB believes COSS B more reasonably reflects cost causation, but did not propose a rate design.

Commission staff's proposed distribution service rates for Prairie du Chien (PdC) residential customers moves towards aligning these rates with those of other MGE residential customers, as ordered in docket 3270-UR-112. The PdC residential customer charge is increased from $0.2493 to $0.2809 per day. The level of the PdC residential distribution charge is set equal to that of other MGE residential customers. As directed by the order in docket 3270-UR-112, the customer charge of PdC residential customers will be set equal with the customer charge of MGE's other customers in its next rate proceeding.

With regard to WCCF, MGE's COSS methodology assumed that the facility would elect 10,342 Dth per day of firm distribution service and receive the balance of its distribution service on an interruptible basis, thereby allocating less distribution costs to the facility than to other customers served on a totally firm basis. Commission staff's COSS methodology assumed that WCCF would be served with only firm distribution capacity, allocating distribution mains costs to the facility in the same manner as other customers that receive firm distribution service.

Consistent with the Commission's determination that WCCF's SP-1 distribution service tariff should only offer firm distribution service, it is reasonable to authorize Commission staff's rate design which reflects the cost of totally firm distribution service for the facility.

Commission staff's rate design is appropriate, when adjusted for the final revenue requirement. Appendix C shows the class revenues and rate design approved by the Commission.

Combining of Gas Costs for the Former Viroqua Municipal Natural Gas Utility and MGE

In joint dockets 3390-GA-100 and 3270-GB-100 the Commission ordered MGE to maintain a separate cost of gas for the former Viroqua Municipal Natural Gas Utility's (MUNY) service territory as long as MUNY's cost of gas was less than MGE's. If in the future, MGE's natural gas costs were to become less expensive than MUNY's, MGE was to propose combining the cost of natural gas for both areas. In this docket MGE presented evidence that the Viroqua customers would realize a sustained benefit from combining the two separate gas costs into a combined gas cost. MGE proposes that this change take place on November 1, 2005, coincident with the start of the pipeline gas year.

The Commission is persuaded by the evidence that, on the whole, the Viroqua customers will see a benefit from the proposed combination of MUNY's and MGE's gas costs and that the combination is reasonable. Further, it is reasonable that this change should take place and become effective November 1, 2005, to coincide with the start of the interstate natural gas pipeline gas year.

Effective Date

The test year for MGE commences on January 1, 2005. Under Wis. Stat. § 196.40, an order or determination of the Commission shall take effect 20 days after the order or determination has been filed and served on the parties to the proceeding unless the Commission specifies a different effective date in the order or determination.

The Commission finds that it is reasonable for this decision to be effective the later of one day after the date of mailing or January 1, 2005, 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 January 1, 2005, the rates shall become effective on the date that the rates are filed with the Commission and placed in all offices and pay stations.

Order

1. This order shall be effective the later of one day after the date of mailing or January 1, 2005, 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 January 1, 2005, the rates shall become effective on the date the rates are filed with the Commission and placed in all offices and pay stations.

2. MGE shall prepare bill inserts that properly identify the rates authorized in this order. MGE shall distribute these inserts to customers with the first billing containing the rates authorized in this order and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

3. MGE is authorized to substitute, for its existing rates and rules for electric and natural gas utility service, the rate and rule changes contained in Appendices B and C. These changes shall be in effect until the issuance of an order by the Commission establishing new rates and rules.

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

5. MGE is authorized to modify its Electric Risk Management Plan as proposed by the company, and extend the plan through the end of 2005.

6. MGE shall record a regulatory asset in lieu of the debit to OCI associated with recording the additional minimum pension liability and shall file a funding plan with the Commission by April 1, 2005. Such funding plan shall include the information discussed in the opinion section of this order.

7. MGE shall account for WCCF facility lease payments on an escrow basis through December 31, 2005.

8. MGE shall continue escrow accounting through December 31, 2005, for those ATC-related transmission expenses that are currently being escrowed.

9. MGE shall defer the net revenue requirement impact resulting from any settlement it may receive pertaining to a claim filed by WPSC for damages over a dispute relating to the storage of spent nuclear fuel.

10. MGE shall defer the revenue requirement impacts associated with the American Jobs Creation Act of 2004 until such time that the impacts can be reflected in a future rate proceeding.

11. MGE shall work with Commission staff to develop measures of success for its 2005 customer service conservation activities, using the 2004 measures of success as the starting point.

12. MGE shall continue accounting for allowable electric and gas conservation expenditures on an escrow basis.

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

14. MGE may not pay dividends to its parent holding company in excess of the amount used to calculate the amount of equity in the utility's capital structure during the test year if its common equity ratio, on a financial basis, is below the 55 percent to 60 percent range established by the Commission. MGE may pay dividends to its parent holding company in excess of this amount if it can show that MGE Energy has issued a greater number of shares than the number used in the forecast, and the proceeds of those shares have been invested in MGE. Prior to paying any dividends under this exception, MGE shall provide an analysis to the Commission making this showing.

15. MGE shall submit a 10-year financial forecast with its next rate case application.

16. MGE shall combine MUNY's gas costs with MGE's gas costs effective November 1, 2005, and shall file revised tariff sheets to reflect this combination.

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)
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ELECTRIC RETAIL REVENUE SUMMARY
TEST YEAR ENDING DECEMBER 31, 2005

Rate Sched.	RATE CLASS	PRESENT REVENUES	AUTHORIZED REVENUES	AUTHORIZED DOLLAR INCREASE	AUTHORIZED PERCENT INCREASE
Rg-1	Residential	$ 95,173,183	$ 103,152,441	$ 7,979,258	8.38%
Rg-2	Residential Time-of-Use	$ 706,346	$ 764,971	$ 58,625	8.30%
Rw-1	Residential Controlled Water Heating	$ 16,878	$ 18,266	$ 1,388	8.23%
Rg-3	Residential Lifeline (Closed)	$ 14,793	$ 15,890	$ 1,097	7.42%
	TOTAL RESIDENTIAL	$ 95,911,199	$ 103,951,568	$ 8,040,368	**8.38%**
Cg-5	Small C&I Lighting and Power (<20 kW)	$ 22,348,443	$ 24,640,381	$ 2,291,938	10.26%
Cg-3	Small C&I Optional Time-of-use (<20 kW)	$ 511,727	$ 560,976	$ 49,249	9.62%
Cg-1A	C&I Lighting and Power (20-75 kW)	$ 24,107,402	$ 26,918,084	$ 2,810,682	11.66%
Cg-1B	C&I Lighting and Power (76-200 kW)	$ 22,187,415	$ 24,825,234	$ 2,637,820	11.89%
Cg-4A	C&I Optional Time-of-Use (20-75 kW)	$ 888,675	$ 989,337	$ 100,662	11.33%
Cg-4B	C&I Optional Time-of-Use (76-200kW)	$ 2,151,716	$ 2,404,513	$ 252,797	11.75%
	TOTAL SMALL COMMERCIAL & INDUSTRIAL	$ 72,195,378	$ 80,338,526	$ 8,143,149	**11.28%**
Cg-2	C&I Lighting and Power Time-of-Use (>200 kW)	$ 58,469,664	$ 65,382,143	$ 6,912,479	11.82%
Cg-6	C&I Lighting & Power Lg. Annual High Load Factor (>1 MW)	$ 8,489,730	$ 9,499,090	$ 1,009,360	11.89%
Cp-1	C&I High Load Factor Direct Control Interruptible - Trans. Volt.	$ 2,954,304	$ 3,317,623	$ 363,319	12.30%
Sp-3	University of Wisconsin Time-of-Use	$ 18,793,389	$ 20,979,134	$ 2,185,745	11.63%
Sp-4	Oscar Mayer Foods Corporation Time-of-Use	$ 3,986,947	$ 4,463,397	$ 476,450	11.95%
Sp-5	Capitol Heat, Light, and Power Time-of-Use	$ 298,968	$ 323,577	$ 24,609	8.23%
	TOTAL LARGE COMMERCIAL & INDUSTRIAL	$ 92,993,003	$ 103,964,966	$ 10,971,963	**11.80%**
Gf-1	General Flat Rate	$ 296,681	$ 322,313	$ 25,632	8.64%
Mg-2	Secondary Service for Municipal Defense Sirens	$ 1,208	$ 1,316	$ 108	8.96%
MLS	Athletic Field Lighting	$ 65,027	$ 71,074	$ 6,047	9.30%
OL-1	Outdoor Overhead Lighting Service - Private Unmetered	$ 394,427	$ 432,042	$ 37,615	9.54%
	TOTAL MISCELLANEOUS AND LIGHTING	$ 757,343	$ 826,745	$ 69,402	**9.16%**
SL-1	Street Lighting Service - Company-Owned & Maintained	$ 150,502	$ 165,460	$ 14,958	9.94%
SL-2	Street Lighting Service - Customer-Owned & Maintained	$ 352,385	$ 388,289	$ 35,904	10.19%
SL-3	Street Lighting Service - Customer-Owned & Co.-Maintained	$ 472,552	$ 524,095	$ 51,543	10.91%
	TOTAL STREET LIGHTING SERVICE	$ 975,439	$ 1,077,844	$ 102,405	**10.50%**
BGS	Backup Generation Service	$ 425,937	$ 425,937	$ -	0.00%
RWE-1	Residential Wind Energy Program	$ 396,827	$ 396,827	$ -	0.00%
BWE-1	Business Wind Energy Program	$ 116,057	$ 116,057	$ -	0.00%
TOTAL RETAIL ELECTRIC SALES REVENUE		$ 263,771,183	$ 291,098,470	$ 27,327,287	10.36%
	Interdepartmental	$ 553,474	$ 613,654	$ 60,179	10.87%
TOTAL RETAIL ELECTRIC SALES REVENUE (w/Interdepartmental)		$ 264,324,657	$ 291,712,124	$ 27,387,467	**10.36%**

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
RESIDENTIAL SERVICE Rg-1						
Customer Charge	$7.50	$0.24670	per bill per day	$0.26300	per bill per day	$8.00
Distribution Charge		$0.02620	per kWh	$0.02840	per kWh	
Electricity Charges:						
Winter Electricity		$0.07048	per kWh	$0.07665	per kWh	
Summer Electricity		$0.07980	per kWh	$0.08664	per kWh	
RESIDENTIAL TIME OF USE Rg-2						
Customer Charge	$10.00	$0.32890	per bill per day	$0.29589	per bill per day	$9.00
Distribution Charge		$0.02620	per kWh	$0.02840	per kWh	
Electricity Charges:						
Winter On-Peak Electricity		$0.14700	per kWh	$0.15560	per kWh	
Winter Off-Peak Electricity		$0.01900	per kWh	$0.02420	per kWh	
Summer On-Peak Electricity		$0.17350	per kWh	$0.18210	per kWh	
Summer Off-Peak Electricity		$0.01900	per kWh	$0.02420	per kWh	
RESIDENTIAL CONTROLLED WATER HEATING Rw-1						
Customer Charge	$2.85	$0.09370	per bill per day	$0.09860	per bill per day	$3.00
Distribution Charge		$0.02620	per kWh	$0.02840	per kWh	
Electricity Charges:						
Winter Electricity		$0.03000	per kWh	$0.03300	per kWh	
Summer Electricity		$0.03600	per kWh	$0.03900	per kWh	
RESIDENTIAL LIFELINE Rg-3						
Customer Charge	$4.00	$0.13160	per bill per day	$0.14300	per bill per day	$4.35
Distribution Charge		$0.02620	per kWh	$0.02840	per kWh	
Electricity Charges:						
Winter First 300 kWh per month		$0.04300	per kWh	$0.04514	per kWh	
Winter Over 300 kWh per month		$0.07048	per kWh	$0.07665	per kWh	
Summer First 300 kWh per month		$0.05020	per kWh	$0.05213	per kWh	
Summer Over 300 kWh per month		$0.07980	per kWh	$0.08664	per kWh	
SMALL C/I LIGHTING & POWER Cg-5 (0-20 kW)						
Customer Charge	$8.00	$0.26300	per bill per day	$0.26300	per bill per day	$8.00
Distribution Charge		$0.02620	per kWh	$0.02840	per kWh	
Electricity Charges:						
Winter Electricity		$0.06840	per kWh	$0.07665	per kWh	
Summer Electricity		$0.07780	per kWh	$0.08664	per kWh	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION		Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
SMALL C/I OPTIONAL TIME OF USE Cg-3 (<20 kW)							
Customer Charge							
Single Phase		$11.25	$0.36990	per bill per day	$0.29590	per bill per day	$9.00
Three Phase		$17.25	$0.56700	per bill per day	$0.56700	per bill per day	$17.25
Distribution Charge			$0.02620	per kWh	$0.02840	per kWh	
Electricity Charges:							
Winter On-Peak Electricity			$0.14400	per kWh	$0.15560	per kWh	
Winter Off-Peak Electricity			$0.01900	per kWh	$0.02420	per kWh	
Summer On-Peak Electricity			$0.17000	per kWh	$0.18210	per kWh	
Summer Off-Peak Electricity			$0.01900	per kWh	$0.02420	per kWh	
C/I LIGHTING & POWER SERVICE Cg-1 LEVEL A (20-75 kW)							
Customer Charge		$31.00	$1.01920	per bill per day	$1.10140	per bill per day	$33.50
Distribution Charge							
Customer Maximum Demand		$3.10	$0.10192	per kW per day	$0.11014	per kW per day	$3.35
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
Energy:	Winter		$0.04560	per kWh	$0.05225	per kWh	
	Summer		$0.05530	per kWh	$0.06225	per kWh	
Limiter Energy:	Winter		$0.00000	per kWh	$0.00000	per kWh	
	Summer		$0.00000	per kWh	$0.00000	per kWh	
C/I LIGHTING & POWER SERVICE Cg-1 LEVEL B (76-200 kW)							
Customer Charge		$31.00	$1.0192	per bill per day	$1.10140	per bill per day	$33.50
Distribution Charge							
Customer Maximum Demand		$3.10	$0.10192	per kW per day	$0.11014	per kW per day	$3.35
Electricity Charges:							
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
Energy:	Winter		$0.04560	per kWh	$0.05225	per kWh	
	Summer		$0.05530	per kWh	$0.06225	per kWh	
C/I LIGHTING & POWER TIME-OF-USE SERVICE Cg-4 LEVEL A (20-75 kW)							
Customer Charge							
Single Phase		$35.00	$1.15070	per bill per day	$1.24940	per bill per day	$38.00
Three Phase		$45.00	$1.47960	per bill per day	$1.61096	per bill per day	$49.00
Distribution Charge							
Customer Maximum Demand		$3.10	$0.10192	per kW per day	$0.11014	per kW per day	$3.35
Electricity Charges:							
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
On-Peak Energy	Winter		$0.07080	per kWh	$0.08035	per kWh	
	Summer		$0.08000	per kWh	$0.09015	per kWh	
Off peak Energy	Winter		$0.03300	per kWh	$0.03675	per kWh	
	Summer		$0.03300	per kWh	$0.03675	per kWh	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION		Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
C/I LIGHTING & POWER TIME-OF-USE SERVICE Cg-4 LEVEL B (76-200 kW)							
Customer Charge							
Single Phase		$35.00	$1.15070	per bill per day	$1.24940	per bill per day	$38.00
Three Phase		$45.00	$1.47960	per bill per day	$1.61096	per bill per day	$49.00
Distribution Charge							
Customer Maximum Demand		$3.10	$0.10192	per kW per day	$0.11014	per kW per day	$3.35
Electricity Charges:							
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
On-Peak Energy	Winter		$0.06950	per kWh	$0.08035	per kWh	
	Summer		$0.07900	per kWh	$0.09015	per kWh	
Off peak Energy	Winter		$0.03300	per kWh	$0.03675	per kWh	
	Summer		$0.03300	per kWh	$0.03675	per kWh	
C/I LIGHTING & POWER SERVICE TIME-OF-USE CG-2 (OVER 200 kW)							
Customer Charge		$125.00	$4.10960	per bill per day	$4.43850	per bill per day	$135.00
Distribution Charges							
Customer Maximum Demand		$3.70	$0.12160	per kW per day	$0.13150	per kW per day	$4.00
Electricity Charges:							
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
On-Peak Energy	Winter		$0.05350	per kWh	$0.06175	per kWh	
	Summer		$0.06100	per kWh	$0.06925	per kWh	
Off peak Energy	Winter		$0.03100	per kWh	$0.03475	per kWh	
	Summer		$0.03100	per kWh	$0.03475	per kWh	
C/I LIGHTING & POWER SERVICE TIME-OF-USE HLF CG-6 (OVER 1 MW)							
Customer Charge		$125.00	$4.1096	per bill per day	$4.43850	per bill per day	$135.00
Distrib. Charges	Cust. Max. kW	$3.75	$0.12330	per kW per day	$0.13480	per kW per day	$4.10
Electricity Charges:							
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
On-Peak Energy	Winter		$0.0488	per kWh	$0.05505	per kWh	
	Summer		$0.0557	per kWh	$0.06195	per kWh	
Off peak Energy	Winter		$0.0302	per kWh	$0.03425	per kWh	
	Summer		$0.0302	per kWh	$0.03425	per kWh	
C/I HIGH LOAD FACTOR DIRECT CONTROL INTERRUPTIBLE SERVICE TRANS. VOLTAGE Cp-1							
Customer Charge		$600.00	$19.72600	per bill per day	$21.37000	per bill per day	$650.00
Electricity Charges:							
Max. Monthly Demand:	Winter	$1.17	$0.03850	per kW per day	$0.05523	per kW per day	$1.68
	Summer	$1.32	$0.04350	per kW per day	$0.07003	per kW per day	$2.13
On-Peak Energy	Winter		$0.03480	per kWh	$0.03650	per kWh	
	Summer		$0.04473	per kWh	$0.04650	per kWh	
Off peak Energy	Winter		$0.02100	per kWh	$0.02420	per kWh	
	Summer		$0.02100	per kWh	$0.02420	per kWh	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION		Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
UNIVERSITY OF WISCONSIN TIME-OF-USE SP-3							
Customer Charge		$5,600.01	$184.1100	per bill per day	$197.2602	per bill per day	$6,000.00
Distrib. Charges	Cust.Max.kW	$2.60	$0.08550	per kW per day	$0.09200	per kW per day	$2.80
Electricity Charges:							
Max. Monthly Demand:	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
On-Peak Energy	Winter		$0.05000	per kWh	$0.05655	per kWh	
	Summer		$0.05440	per kWh	$0.06155	per kWh	
Off peak Energy	Winter		$0.03210	per kWh	$0.03625	per kWh	
	Summer		$0.03210	per kWh	$0.03625	per kWh	
OSCAR MAYER TIME-OF-USE SP-4							
Customer Charge		$210.00	$6.90400	per day per bill	$7.39730	per day per bill	$225.00
Distribution Charges							
Customer Maximum Demand		$2.60	$0.08550	per kW per day	$0.09370	per kW per day	$2.85
Electricity Charges:							
Firm Contract Demand	Winter	$5.32	$0.17500	per kW per day	$0.19068	per kW per day	$5.80
	Summer	$6.54	$0.21500	per kW per day	$0.23671	per kW per day	$7.20
On-Peak Energy	Winter		$0.04830	per kWh	$0.05455	per kWh	
	Summer		$0.05280	per kWh	$0.05955	per kWh	
Off peak Energy	Winter		$0.03020	per kWh	$0.03425	per kWh	
	Summer		$0.03020	per kWh	$0.03425	per kWh	
Supplemental Energy	Winter		$0.04830	per kWh	$0.05455	per kWh	
	Summer		$0.05280	per kWh	$0.05955	per kWh	
CAPITOL HEATING TIME-OF-USE SP5							
Customer Charge		$570.00	$18.73970	per day per bill	$20.21930	per day per bill	$615.00
Distribution Charges							
Customer Maximum Demand		$2.60	$0.08550	per kW per day	$0.09205	per kW per day	$2.80
Electricity Charges:							
Max. Monthly Demand:	Winter	$6.40	$0.21050	per kW per day	$0.22521	per kW per day	$6.85
	Summer	$7.60	$0.25000	per kW per day	$0.26960	per kW per day	$8.20
On-Peak Energy	Winter		$0.05600	per kWh	$0.06275	per kWh	
	Summer		$0.06100	per kWh	$0.06775	per kWh	
Off peak Energy	Winter		$0.03020	per kWh	$0.03425	per kWh	
	Summer		$0.03020	per kWh	$0.03425	per kWh	
SUMMER CURTAILABLE SERVICE (SCS)							
Cg-1 Summer Interruptible kW		($6.00)	($0.19726)	per kW per day	($0.19726)	per kW per day	($6.00)
Cg-4 Summer Interruptible kW		($6.00)	($0.19726)	" " " "	($0.19726)	" " " "	($6.00)
Cg-2 Summer Interruptible kW		($6.00)	($0.19726)	" " " "	($0.19726)	" " " "	($6.00)
Cg-6 Summer Interruptible kW		($6.00)	($0.19726)	" " " "	($0.19726)	" " " "	($6.00)
Sp-3 Summer Interruptible kW		($6.00)	($0.19726)	" " " "	($0.19726)	" " " "	($6.00)

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
INTERRUPTIBLE SERVICE RIDER Is-1						
Variable Pricing						
Cg-2 Winter Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Cg-2 Summer Interruptible kW	($3.75)	($0.12329)	" " " "	($0.12329)	" " " "	($3.75)
Cg-6 Winter Interruptible kW	($3.75)	($0.12329)	" " " "	($0.12329)	" " " "	($3.75)
Cg-6 Summer Interruptible kW	($3.75)	($0.12329)	" " " "	($0.12329)	" " " "	($3.75)
Sp-3 Winter Interruptible kW	($3.75)	($0.12329)	" " " "	($0.12329)	" " " "	($3.75)
Sp-3 Summer Interruptible kW	($3.75)	($0.12329)	" " " "	($0.12329)	" " " "	($3.75)
Fixed Pricing						
Cg-2 Winter Interruptible kW	($3.00)	($0.09863)	per kW per day	($0.09863)	per kW per day	($3.00)
Cg-2 Summer Interruptible kW	($3.00)	($0.09863)	" " " "	($0.09863)	" " " "	($3.00)
Cg-6 Winter Interruptible kW	($3.00)	($0.09863)	" " " "	($0.09863)	" " " "	($3.00)
Cg-6 Summer Interruptible kW	($3.00)	($0.09863)	" " " "	($0.09863)	" " " "	($3.00)
Sp-3 Winter Interruptible kW	($3.00)	($0.09863)	" " " "	($0.09863)	" " " "	($3.00)
Sp-3 Summer Interruptible kW	($3.00)	($0.09863)	" " " "	($0.09863)	" " " "	($3.00)
DIRECT CONTROL INTERRUPTIBLE SERVICE RIDER Is-2						
Variable Pricing						
Cg-1 Winter Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-1 Summer Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Cg-4 Winter Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Cg-4 Summer Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Cg-2 Winter Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Cg-2 Summer Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Cg-6 Winter Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Cg-6 Summer Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Sp-3 Winter Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Sp-3 Summer Interruptible kW	($4.00)	($0.13151)	" " " "	($0.13151)	" " " "	($4.00)
Fixed Pricing						
Cg-1 Winter Interruptible kW	($3.25)	($0.10685)	per kW per day	($0.10685)	per kW per day	($3.25)
Cg-1 Summer Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Cg-4 Winter Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Cg-4 Summer Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Cg-2 Winter Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Cg-2 Summer Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Cg-6 Winter Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Cg-6 Summer Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Sp-3 Winter Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
Sp-3 Summer Interruptible kW	($3.25)	($0.10685)	" " " "	($0.10685)	" " " "	($3.25)
MISCELLANEOUS FLAT RATE SERVICE GF-1						
LEVEL I Telephone Booths		$5.00	per bill per unit	$5.50	per bill per unit	
LEVEL II CATV Amplifiers		$50.70	per bill per unit	$55.08	per bill per unit	
LEVEL III Unmetered Service						
Customer Charge	$8.00	$0.26300	per day per bill	$0.26300	per day per bill	$8.00
Distribution Service		$0.02620	per kWh	$0.02840	per kWh	
Electricity Service		$0.06100	per kWh	$0.06920	per kWh	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
SECONDARY SERVICE FOR MUNICIPAL DEFENSE SIRENS Mg-2						
Motor-Driven Sirens		$2.86	per bill per unit	$3.10	per bill per unit	
Electronic Sirens		$4.16	per bill per unit	$4.55	per bill per unit	
ATHLETIC FIELD LIGHTING MLS						
Customer Charge	$8.00	$0.26300	per day per bill	$0.26300	per day per bill	$8.00
Distribution Charge		$0.02620	per kWh	$0.02840	per kWh	
Electric Charge		$0.06680	per kWh	$0.07350	per kWh	
OUTDOOR OVERHEAD LIGHTING SERVICE -- OL-1 (PRIVATE UNMETERED)						
DUSK-TO-DAWN YARD LIGHTING						
150 WATT HPS LAMPS		$11.40	per lamp per bill	$12.40	per lamp per bill	
100 WATT HPS LAMPS		$9.80	" " " "	$10.70	" " " "	
70 WATT HPS LAMPS		$8.90	" " " "	$9.75	" " " "	
400 WATT MV LAMPS		$21.00	" " " "	$22.80	" " " "	
250 WATT MV LAMPS		$15.40	" " " "	$16.80	" " " "	
175 WATT MV LAMPS		$12.90	" " " "	$14.10	" " " "	
SECURITY FLOOD LIGHTING						
400 WATT HPS LAMPS		$20.50	per lamp per bill	$22.10	per lamp per bill	
250 WATT HPS LAMPS		$16.00	" " " "	$17.30	" " " "	
150 WATT HPS LAMPS		$11.40	" " " "	$12.40	" " " "	
70 WATT HPS LAMPS		$8.90	" " " "	$9.75	" " " "	
400 WATT MH LAMPS		$22.60	" " " "	$24.20	" " " "	
250 WATT MH LAMPS		$18.00	" " " "	$19.30	" " " "	
POLES: Wood		$4.65	per pole per bill	$5.40	per pole per bill	
Non-Wood		$12.10	" " " "	$13.00	" " " "	
STREET LIGHTING SERVICE -- SL-1 (COMPANY OWNED AND COMPANY MAINTAINED)						
Distribution Service Charge		$2.35	per lamp per bill	$2.50	per lamp per bill	
Electricity Service Unit Charge		$0.04900	per kWh	$0.05550	per kWh	
OVERHEAD SERVICE (Facilities Charges)						
400 WATT MV		$8.00	per lamp per bill	$8.50	per lamp per bill	
250 WATT MV		$5.60	" " " "	$6.00	" " " "	
175 WATT MV		$4.70	" " " "	$5.20	" " " "	
250 WATT HPS		$5.95	" " " "	$6.55	" " " "	
200 WATT HPS		$4.75	" " " "	$5.25	" " " "	
150 WATT HPS		$3.80	" " " "	$4.20	" " " "	
100 WATT HPS		$3.10	" " " "	$3.45	" " " "	
70 WATT HPS		$2.80	" " " "	$3.10	" " " "	
300 WATT INC		$5.00	" " " "	$5.60	" " " "	
MIDNIGHT						
400 WATT MV MN		$8.00	" " " "	$8.50	" " " "	
250 WATT MV MN		$5.60	" " " "	$6.00	" " " "	
UNDERGROUND SERVICE (Facilities Charges)						
250 WATT HPS ANEN		$14.20	per lamp per bill	$15.50	per lamp per bill	
200 WATT HPS ANEN		$13.00	" " " "	$14.30	" " " "	
150 WATT HPS ANEN		$12.00	" " " "	$13.20	" " " "	
100 WATT HPS ANEN		$11.25	" " " "	$12.40	" " " "	
70 WATT HPS ANEN		$11.00	" " " "	$12.10	" " " "	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
STREET LIGHTING SERVICE -- SL-2 (CUSTOMER OWNED AND CUSTOMER MAINTAINED)						
Distribution Service Charge		$2.35	per lamp per bill	$2.50	per lamp per bill	
Electricity Service Unit Charge		$0.04900	per kWh	$0.05550	per kWh	
Note: Below are the monthly SL-2 charges/lamp resulting from the Distribution Service & Electricity Service Charges, above)						
ALL NIGHT						
1000-WATT MV ANEN		$18.667	per lamp per bill	$20.98	per lamp per bill	
400-WATT MV ANEN		$8.867	" " " "	$9.88	" " " "	
250-WATT MV ANEN		$6.417	" " " "	$7.11	" " " "	
175-WATT MV ANEN		$5.192	" " " "	$5.72	" " " "	
100-WATT MV ANEN		$3.967	" " " "	$4.33	" " " "	
400-WATT HPS ANEN		$8.867	" " " "	$9.88	" " " "	
250-WATT HPS ANEN		$6.417	" " " "	$7.11	" " " "	
200-WATT HPS ANEN		$5.633	" " " "	$6.22	" " " "	
150-WATT HPS ANEN		$4.800	" " " "	$5.28	" " " "	
100-WATT HPS ANEN		$3.967	" " " "	$4.33	" " " "	
70-WATT HPS ANEN		$3.477	" " " "	$3.78	" " " "	
35-WATT HPS ANEN		$2.938	" " " "	$3.17	" " " "	
90-WATT LPS ANEN		$3.820	" " " "	$4.17	" " " "	
55-WATT LPS ANEN		$3.232	" " " "	$3.50	" " " "	
35 WATT LPS ANEN		$2.938	" " " "	$3.17	" " " "	
175-WATT MH ANEN		$5.192	" " " "	$5.72	" " " "	
100-WATT MH ANEN		$3.967	" " " "	$4.33	" " " "	
70-WATT MH ANEN		$3.477	" " " "	$3.78	" " " "	
MIDNIGHT SCHEDULE						
400-WATT MV MN		$5.633	per lamp per bill	$6.22	per lamp per bill	
250-WATT MV MN		$4.408	" " " "	$4.83	" " " "	
400-WATT HPS MN		$5.633	" " " "	$6.22	" " " "	
250-WATT HPS MN		$4.408	" " " "	$4.83	" " " "	
200-WATT HPS MN		$3.967	" " " "	$4.33	" " " "	
150-WATT HPS MN		$3.575	" " " "	$3.89	" " " "	
100-WATT HPS MN		$3.183	" " " "	$3.44	" " " "	
70-WATT HPS MN		$2.938	" " " "	$3.17	" " " "	
35-WATT HPS MN		$2.644	" " " "	$2.83	" " " "	
90-WATT LPS MN		$3.085	" " " "	$3.33	" " " "	
55-WATT LPS MN		$2.791	" " " "	$3.00	" " " "	
35 WATT LPS MN		$2.644	" " " "	$2.83	" " " "	
175-WATT MH MN		$3.771	" " " "	$4.11	" " " "	
100-WATT MH MN		$3.183	" " " "	$3.44	" " " "	
70-WATT MH MN		$2.938	" " " "	$3.17	" " " "	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
STREET LIGHTING SERVICE -- SL-2 (CUSTOMER OWNED & MAINTAINED) (Continued)						
10:30 P.M. SCHEDULE						
400-WATT MV 10:30		$4.702	per lamp per bill	$5.16	per lamp per bill	
400-WATT HPS 10:30		$4.702	" " " "	$5.16	" " " "	
250-WATT HPS 10:30		$3.820	" " " "	$4.17	" " " "	
200-WATT HPS 10:30		$3.526	" " " "	$3.83	" " " "	
150-WATT HPS 10:30		$3.232	" " " "	$3.50	" " " "	
100-WATT HPS 10:30		$2.938	" " " "	$3.17	" " " "	
70-WATT HPS 10:30		$2.742	" " " "	$2.94	" " " "	
35-WATT HPS 10:30		$2.546	" " " "	$2.72	" " " "	
90-WATT LPS 10:30		$2.889	" " " "	$3.11	" " " "	
55-WATT LPS 10:30		$2.693	" " " "	$2.89	" " " "	
35 WATT LPS 10:30		$2.546	" " " "	$2.72	" " " "	
70-WATT MH 10:30		$2.742	" " " "	$2.94	" " " "	
3:00 A.M. SCHEDULE						
100-WATT MV 3AM		$3.575	per lamp per bill	$3.89	per lamp per bill	
400-WATT HPS 3AM		$7.250	" " " "	$8.05	" " " "	
250-WATT HPS 3AM		$5.437	" " " "	$6.00	" " " "	
200-WATT HPS 3AM		$4.800	" " " "	$5.28	" " " "	
150-WATT HPS 3AM		$4.212	" " " "	$4.61	" " " "	
100-WATT HPS 3AM		$3.575	" " " "	$3.89	" " " "	
70-WATT HPS 3AM		$3.232	" " " "	$3.50	" " " "	
35-WATT HPS 3AM		$2.791	" " " "	$3.00	" " " "	
90-WATT LPS 3AM		$3.477	" " " "	$3.78	" " " "	
55-WATT LPS ANEN		$3.036	" " " "	$3.28	" " " "	
35 WATT LPS ANEN		$2.791	" " " "	$3.00	" " " "	
175-WATT MH 3AM		$4.506	" " " "	$4.94	" " " "	
100-WATT MH 3AM		$3.575	" " " "	$3.89	" " " "	
70-WATT MH 3AM		$3.232	" " " "	$3.50	" " " "	
STREET LIGHTING SERVICE -- SL-3 (CUSTOMER OWNED AND COMPANY MAINTAINED)						
Distribution Service Charge		$2.35	per lamp per bill	$2.50	per lamp per bill	
Electricity Service Unit Charge		$0.04900	per kWh	$0.05550	per kWh	
OVERHEAD SERVICE (Maintenance Charges)						
ALL NIGHT SCHEDULE						
400 WATT HPS ANEN		$4.510	per lamp per bill	$4.45	per lamp per bill	
250 WATT HPS ANEN		$2.300	" " " "	$2.30	" " " "	
200 WATT HPS ANEN		$1.550	" " " "	$1.55	" " " "	
150 WATT HPS ANEN		$0.800	" " " "	$0.95	" " " "	
100 WATT HPS ANEN		$0.750	" " " "	$0.90	" " " "	
70 WATT HPS ANEN		$0.350	" " " "	$0.55	" " " "	
MIDNIGHT SCHEDULE						
400 WATT HPS MN		$1.520	per lamp per bill	$1.55	per lamp per bill	
250 WATT HPS MN		$0.800	" " " "	$1.00	" " " "	
200 WATT HPS MN		$0.800	" " " "	$1.00	" " " "	
150 WATT HPS MN		$0.700	" " " "	$0.95	" " " "	
100 WATT HPS MN		$0.400	" " " "	$0.60	" " " "	
70 WATT HPS MN		$0.350	" " " "	$0.55	" " " "	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
STREET LIGHTING SERVICE -- SL-3 (CUSTOMER OWNED AND COMPANY MAINTAINED) (Continued)						
OVERHEAD SERVICE (Maintenance Charges)						
3:00 A.M. SCHEDULE						
400-WATT HPS 3AM		$3.020	per lamp per bill	$3.00	per lamp per bill	
250-WATT HPS 3AM		$1.350	" " " "	$1.40	" " " "	
200-WATT HPS 3AM		$0.800	" " " "	$1.00	" " " "	
150-WATT HPS 3AM		$0.700	" " " "	$0.95	" " " "	
100-WATT HPS 3AM		$0.400	" " " "	$0.60	" " " "	
70-WATT HPS 3AM		$0.350	" " " "	$0.55	" " " "	
UNDERGROUND SERVICE (Maintenance Charges)						
ALL NIGHT SCHEDULE						
175 WATT MV ANEN		$1.000	per lamp per bill	$1.08	per lamp per bill	
250 WATT MV ANEN		$2.120	" " " "	$2.12	" " " "	
250 WATT HPS ANEN		$2.300	" " " "	$2.30	" " " "	
200 WATT HPS ANEN		$1.550	" " " "	$1.55	" " " "	
150 WATT HPS ANEN		$0.800	" " " "	$0.95	" " " "	
100 WATT HPS ANEN		$0.750	" " " "	$0.90	" " " "	
70 WATT HPS ANEN		$0.350	" " " "	$0.55	" " " "	
MIDNIGHT SCHEDULE						
400 WATT HPS MN		$1.520	" " " "	$1.55	" " " "	
250 WATT HPS MN		$0.800	" " " "	$1.00	" " " "	
200 WATT HPS MN		$0.800	" " " "	$1.00	" " " "	
150 WATT HPS MN		$0.700	" " " "	$0.95	" " " "	
100 WATT HPS MN		$0.400	" " " "	$0.60	" " " "	
70 WATT HPS MN		$0.350	" " " "	$0.55	" " " "	
BACKUP GENERATION SERVICE (BGS)						
Diesel Generators	$1.50	$0.04932	per kW per day	$0.04932	per kW per day	$1.50
Diesel Generators - New Contract	$2.00	$0.06575	per kW per day	$0.06575	per kW per day	$2.00
Natural Gas Generators	$3.50	$0.11507	per kW per day	$0.11507	per kW per day	$3.50
Natural Gas Generators - New	$4.00	$0.13151	per kW per day	$0.13151	per kW per day	$4.00
RESIDENTIAL WIND ENERGY (RWE-1)						
Incremental Charge for Wind Energy		$0.03330	per kWh	$0.03330	per kWh	
BUSINESS WIND ENERGY (BWE-1)						
Incremental Charge for Wind Energy		$0.03330	per kWh	$0.03330	per kWh	

PRESENT AND AUTHORIZED RATES

RATE CLASS / RATE DESCRIPTION	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
PARALLEL GENERATION (Pg-1)						
Customer Charge						
Single Phase	$6.80	$0.22356	per bill per day	$0.22356	per bill per day	$6.80
Three Phase	$8.00	$0.26300	per bill per day	$0.26300	per bill per day	$8.00
ENERGY PAYMENTS TO CUSTOMER:						
Electric Charge						
Primary Service, On-Peak		$0.0588	per kWh	$0.0780	per kWh	
Primary Service, Off-Peak		$0.0350	per kWh	$0.0411	per kWh	
Secondary Service, On-Peak		$0.0595	per kWh	$0.0769	per kWh	
Secondary Service, Off-Peak		$0.0353	per kWh	$0.0407	per kWh	
PRIMARY & TRANSFORMER DISCOUNTS (Applicable to certain C/I customer classes)						
Primary Voltage Energy Discount		($0.0010)	per kWh	($0.00100)	per kWh	
Primary Voltage Demand Discount	($0.10)	($0.00329)	per kW per day	($0.00329)	per kW per day	($0.10)
Transformer Demand Discount	($0.10)	($0.00329)	per kW per day	($0.00329)	per kW per day	($0.10)

Madison Gas and Electric Company
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Natural Gas Revenue Summary

Customer Class	Volumes	Present Distribution Revenues	Authorized Change in Distrib. Rev.	Authorized Distribution Revenues	% Percent Change
Residential Distribution (RD-1, RD-2)	98,250,676	$ 39,195,124	$ (2,978,287)	$ 36,216,837	-7.60%
Small Commercial / Industrial Distribution (GSD-1)	50,839,072	$ 11,248,813	$ (1,087,956)	$ 10,160,856	-9.67%
Medium Commercial / Industrial Distribution (GSD-2)	33,625,139	$ 4,508,081	$ (215,201)	$ 4,292,880	-4.77%
Large Commercial / Industrial Distribution (GSD-3)	24,659,383	$ 2,063,001	$ (194,809)	$ 1,868,192	-9.44%
Interruptible Generation Distribution (IGD-1)	52,135,963	$ 1,718,632	$ -	$ 1,718,632	-
West Campus Co-Generation Facility (SP-1)*	35,197,283	$ 1,282,744	$ 242,861	$ 1,525,605	-
Seasonal Distribution (SD-1)	2,035,630	$ 198,732	$ -	$ 198,732	-
Compressed Natural Gas Sales Service (CNG-1)	3,740	$ 775	$ -	$ 775	-
Company Use Volume	124,273				
Total Distribution Volumes	296,871,159				
Difference in Present Revenue from forecast		$ 5,560	$ (5,560)	$ -	-
TOTAL REVENUES FROM DISTRIBUTION SERVICE		$ 60,221,461	$ (4,238,952)	$ 55,982,509	-7.04%
	Plus Cost of Gas			$ 171,730,952	
	Total Gas Utility Revenues @ Authorized Rates			$ 227,713,461	-1.83%
	Plus Other Non-gas Operating Revenues			$ 429,000	
	TOTAL REVENUE			$ 228,142,461	

*The SP-1 class is a new distribution service class that would serve West Campus Co-Generation Facility. SP-1 present revenues are included as an estimate. The SP-1 rates are set in this proceeding.

Distribution Service			Supply Options					
	Present	Authorized	Firm Sales			Interruptible Sales		
Customer Class	Rates	Rates	FS Adm.	COG [1]	Total	IS Adm.	COG	Total
Residential, RD-1								
Customer Charge (per day) except Prairie du Chien	$ 0.3124	$ 0.3124			$ 0.3124			N/A
Praire du Chien Customer Charge (per day)	$ 0.2493	$ 0.2809			$ 0.2809			
Distribution Service (Summer per therm)	$ 0.2413	$ 0.2100	$ 0.0191	$ 0.6928	$ 0.9219	N/A	N/A	N/A
Distribution Service (Winter / therm)	$ 0.2413	$ 0.2100		$ 0.7221	$ 0.9512	N/A	N/A	N/A
Residential, RD-2								
Customer Charge (per day)	$ 0.3124	$ 0.3124			$ 0.3124			N/A
Distribution Service (Summer / therm)	$ 0.2413	$ 0.2100	$ 0.0191	$ 0.6928	$ 0.9219	N/A	N/A	N/A
Distribution Service (Winter / therm)	$ 0.2213	$ 0.1900	$ 0.0191	$ 0.7221	$ 0.9312	N/A	N/A	N/A
Small Commercial & Indust., GSD-1								
Customer Charge (per day)	$ 0.5550	$ 0.5550			$ 0.5550			$0.5550
Distribution Service (Summer per therm)	$ 0.1464	$ 0.1250	$ 0.0191	$ 0.6928	$ 0.8369	$ 0.0171	$ 0.6458 [2]	$0.7879
Distribution Service (Winter per therm)	$ 0.1464	$ 0.1250		$ 0.7221	$ 0.8662		(Same rates apply)	
Medium Commercial & Indust., GSD-2								
Customer Charge (per day)	$ 3.397	$ 3.397			$ 3.397			$3.397
Distribution Service (Summer per therm)	$ 0.0900	$ 0.0836	$ 0.0191	$ 0.6928	$ 0.7955	$ 0.0171	$ 0.6458 [2]	$0.7465
Distribution Service (Winter per therm)	$ 0.0900	$ 0.0836		$ 0.7221	$ 0.8248		(Same rates apply)	
Large Commercial & Indust., GSD-3								
Customer Charge (per day)	$ 20.011	$ 20.011			$ 20.011			$20.011
Distribution Service (Summer per therm)	$ 0.0615	$ 0.0536	$ 0.0191	$ 0.6928	$ 0.7655	$ 0.0171	$ 0.6458 [2]	$0.7165
Distribution Service (Winter per therm)	$ 0.0615	$ 0.0536		$ 0.7221	$ 0.7948		(Same rates apply)	
Interruptible Generation, IGD-1								
Customer Charge (per day)	$ 102.00	$ 102.00				$ 30.00		$ 132.00
Distribution Service (Summer per therm)	$ 0.0298	$ 0.0298	N/A	N/A	N/A	$ -	$ 0.6388 [3]	$0.6686
Distribution Service (Winter per therm)	$ 0.0298	$ 0.0298						
West Campus Co-Generation Facility (SP-1)								
Customer Charge (per day)		$ 1,592.88				$ -		$ 1,592.88
Distribution Service (per therm)		$ 0.0319	N/A	N/A	N/A	$ -	$ 0.6388 [3]	$0.6707
Season Distribution, SD-1								
Customer Charge (per day)	$ 1.3875	$ 1.3875						$1.3875
Distribution Service (per therm)	$ 0.0728	$ 0.0728	N/A	N/A	N/A	$ 0.0171	$ 0.6458 [2]	$0.7357
Compressed Natural Gas CNG-1								
Distribution Service (per therm)	$ 0.1900	$ 0.1900	N/A	N/A	N/A	$ 0.0171	$0.6458 [2]	$0.8529

Administrative Charges for Supply Options:

IS-1 Administrative Charge (per therm)	$ 0.0171	$ 0.0171
Added FS costs for Firm Sales (per therm)	$ 0.0020	$ 0.0020
Total FS-1 Admin. Charge (per therm)	$ 0.0191	$ 0.0191
FS-2 Winter Admin. Charge (per therm)	$ 0.0191	$ 0.0191
IS-2 Service Charge (per cust. per day)	$ 30.00	$ 30.00
LS-1 Administrative Charge (per day)	$ 50.00	$ 50.00
Telemetering Charge (per cust. per day)	$ 1.25	$ 1.25
DBS Admin. Charge (per cust. per day)	$ 3.00	$ 3.00

Cost of Gas Rate Factors:

Base Average Annual Demand (D-1 Annual)	$ 0.0470
Base Average Seasonal Demand (D-1 Winter)	$ 0.0293
Base Average GRI Demand	$ -
Base Average Commodity	$ 0.6388
Base Average Balancing Reservation	$ 0.0070
Base Average Transition Charge	$ 0.0009 [4]
Base Average LS-1 Firm Reservation Rate	$ 0.0178

Notes:

(1) The firm COG has seasonal demand costs, so a Summer and Winter COG are listed.

(2) These rates will also be adjusted by a monthly Interruptible Market Reservation factor. IS-1 rates shown in GSD-1 are only available to interruptible service customers that were grandfathered into the class.

(3) The IS-2 Commodity Cost of Gas is the system commodity cost of gas + pipeline overrun cost + Interruptible Market Reservation (IMR) rate (75%). The interruptible portion of LS-1 System Priced Supply Commodity Cost is similarily priced, but doesn't include storage gas. Firm LS-1 gas is covered by the Firm Reservation Rate and doesn't include the IMR rate.

(4) The Transition Charge (FERC Demand) is not included in the COG rates on this page. It is added to all Distribution Margins.

Distribution Service			Supply Options					
	Present	Authorized	Firm Sales			Interruptible Sales		
Customer Class	Rates	Rates	FS Adm.	COG	Total	IS Adm.	COG	Total
Residential, RD-1								
Customer Charge (per day)	$ 0.3124	$ 0.3124			$ 0.3124			
Distribution Margin (per therm)	$ 0.2413	$ 0.2100	$ 0.0191	$ 0.8074	$ 1.0365	N/A	N/A	N/A
Small Commercial & Indust., GSD-1								
Customer Charge (per day)	$ 0.5550	$ 0.5550			$ 0.5550			$0.5550
Distribution Margin (per therm)	$ 0.1464	$ 0.1250	$ 0.0191	$ 0.8074	$ 0.9515	$ 0.0171	$ 0.7511 (1)	$0.8932
Medium Commercial & Indust., GSD-2								
Customer Charge (per day)	$ 3.397	$ 3.397			$ 3.397			$3.397
Distribution Margin (per therm)	$ 0.0900	$ 0.0836	$ 0.0191	$ 0.8074	$ 0.9101	$ 0.0171	$ 0.7511 (1)	$0.8518
Large Commercial & Indust., GSD-3								
Customer Charge (per day)	$ 20.011	$ 20.011			$ 20.011			$20.011
Distribution Margin (per therm)	$ 0.0615	$ 0.0536	$ 0.0191	$ 0.8074	$ 0.8801	$ 0.0171	$ 0.7511 (1)	$0.8218
Season Distribution, SD-1								
Customer Charge (per day)	$ 1.3875	$ 1.3875						$1.3875
Distribution Margin (per therm)	$ 0.0728	$ 0.0728	N/A	N/A	N/A	$ 0.0171	$ 0.7511 (1)	$0.8410

Administrative Charges for Supply Options:

IS-1 Administrative Charge (per therm)	$ 0.0171	$ 0.0171
Added Margin for Firm Sales (per therm)	$ 0.0020	$ 0.0020
Total FS-1 Admin. Charge (per therm)	$ 0.0191	$ 0.0191
FS-2 Winter Admin. Charge (per therm)	$ 0.0191	$ 0.0191
Telemetering Charge (per cust. per day)	$ 1.25	$ 1.25
DBS Admin. Charge (per cust. per day)	$ 3.00	$ 3.00

Cost of Gas Rate Factors*:

Base Average Peak Demand	$ 0.0563
Base Average Annual Demand	$ 0.0003
Base Average Commodity	$ 0.7508
Base Average Transition Charge	$ 0.0010 (2)

Notes:

(1) These rates will also be adjusted by a monthly Interruptible Market Reservation factor. IS-1 rates shown in GSD-1 are only available to interruptible service customers that were grandfathered into the class.

(2) The Transition Charge (FERC Demand) is not included in the COG rates on this page. It is added to all Distribution Margins.

*The cost of gas rate factors for customers in the former Viroqua Municipal Natural Gas Utility's (MUNY) service territory are set at the rates shown above until November 1, 2005. On that date, the gas costs of former MUNY customers will be combined with MGE's other gas costs, and Viroqua's cost of gas rate factors will be set at the same level as other MGE customers.

Appendix D

Madison Gas and Electric Company

Monitored Fuel Costs for 2005

Month	Fuel Costs	kWh	$ / kWh	Cumulative $ / kWh
January	$ 9,094,812	291,635,000	$ 0.03119	$ 0.03119
February	$ 11,063,543	261,654,000	$ 0.04228	$ 0.03643
March	$ 9,213,938	265,126,000	$ 0.03475	$ 0.03589
April	$ 8,299,288	258,884,000	$ 0.03206	$ 0.03497
May	$ 6,210,571	261,252,000	$ 0.02377	$ 0.03278
June	$ 7,716,016	292,900,000	$ 0.02634	$ 0.03163
July	$ 11,667,406	359,633,000	$ 0.03244	$ 0.03177
August	$ 10,299,200	336,629,000	$ 0.03060	$ 0.03160
September	$ 7,416,192	292,314,000	$ 0.02537	$ 0.03091
October	$ 6,674,804	271,206,000	$ 0.02461	$ 0.03032
November	$ 6,707,024	254,565,000	$ 0.02635	$ 0.03000
December	$ 8,014,069	288,492,000	$ 0.02778	$ 0.02981
Total	$ 102,376,863	3,434,290,000	$ 0.02981	$ 0.02981