PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates — 4220-UR-118

FINAL DECISION

This is the Final Decision concerning the application of Northern States Power Company-Wisconsin (NSPW), doing business as Xcel Energy, for authority to increase Wisconsin retail electric and natural gas rates in 2013.

Final overall rate changes are authorized consisting of a $35,532,000 annual rate increase for Wisconsin retail electric operations, a 6.09 percent increase; and a $2,717,000 annual rate increase for Wisconsin retail natural gas operations, a 2.53 percent increase, for the test year ending December 31, 2013, based on a 10.40 percent return on common equity.

Introduction

On June 1, 2012, NSPW filed for authority to increase its Wisconsin retail electric and natural gas rates on January 1, 2013. NSPW requested an overall increase in annual Wisconsin retail electric revenues of $39.1 million, an increase of 6.7 percent over present revenues; or, in the alternative, $41.7 million, an increase of 7.2 percent over present revenues, depending on the Commission’s treatment of cleanup costs for the manufactured gas plant (MGP) site in Ashland, Wisconsin. NSPW also requested an overall increase in annual Wisconsin retail natural gas revenues of $5.3 million, an increase of 4.9 percent; or, in the alternative, $2.7 million, an increase of 2.5 percent over present revenues, depending on the Commission’s treatment of MGP clean-up costs. NSPW’s proposed natural gas increase request was limited solely to recovery of MGP cleanup costs.

On July 31, 2012, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. A hearing was held on November 7, 2012, in Madison, to receive technical information and public comments into the record.

The Commission considered this matter at its open meeting on December 14, 2012. 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. Presently authorized rates for NSPW's Wisconsin retail electric utility operations will produce operating revenues of $583,411,000 for the test year ending December 31, 2013, which results in an adjusted net operating income of $46,300,000 and an annual revenue deficiency of $35,532,000. Presently authorized electric rates of NSPW are insufficient.

2. For the Wisconsin retail electric utility operations, the estimated rate of return on average net investment rate base of $788,602,000 at current rates for the test year is 5.87 percent, which is inadequate.

3. A reasonable increase in operating revenue for the test year to produce an 8.57 percent return on NSPW's average net investment rate base for Wisconsin retail electric operations is $35,532,000.

4. NSPW's filed electric operating income statement and net investment rate base for the test year, as adjusted for Commission decisions, are reasonable.

5. Presently authorized rates for NSPW's Wisconsin retail natural gas utility operations will produce operating revenues of $107,597,000 for the test year ending December 31, 2013.

6. It is reasonable to limit the scope of the natural gas rate increase request to the sole issue of MGP clean-up costs.

7. A 2013 total NSP system test year fuel cost of $1,299.17 million is reasonable.

8. A 2013 total NSP system test year fuel rules monitoring level of fuel costs of $1,130.58 million, or $0.02555 per kilowatt-hour (kWh), as shown in Appendix D, is reasonable.

9. It is reasonable to reflect the signed contract for Green Whey Dairy in fuel costs.

10. It is reasonable to require Commission staff, utilities, and interested intervenors to work together early in 2013 to resolve the issue of the treatment of System Support Resources (SSR) costs. It is reasonable to require Commission staff to prepare and send to the Commission a briefing memorandum outlining the positions of the parties and the alternatives the Commission has to address this issue.

11. It is reasonable to update fuel costs to reflect market prices for electricity, natural gas and heating oil as of November 15, 2012.

12. It is reasonable to allow NSPW to use the final monitored fuel costs as determined by the Commission in this docket for NSPW's fuel cost plan for 2013.

13. It is reasonable to monitor all monitored fuel costs using an annual bandwidth of plus or minus 2 percent.

14. It is reasonable to incorporate actual payroll increases given in 2012 for all employees, a 1.7 percent payroll merit increase in 2013 for non-union employees and a 2.5 percent payroll merit increase in 2013 for union employees under contract in the development of test-year payroll expense and related taxes.

15. It is not reasonable to include the payroll and related costs associated with the annual incentive plan costs in revenue requirements.

16. It is reasonable to include all uncontested Commission staff adjustments to NSPW's filed electric revenue requirements.

17. It is reasonable that the amortization period of the MGP clean-up costs for Ashland be amortized over a ten-year period, that estimates of the 2013 costs for clean-up at the terrestrial site, but not the bay area, be included in the 2013 test-year amortization calculation and resulting revenue requirement, and that the revenue requirement include 3 percent interest on the unamortized balance of the clean-up costs.

18. It is reasonable to continue to assess MGP clean-up costs to gas ratepayers only.

19. NSPW's proposed voluntary energy efficiency programs are reasonable.

20. It is not reasonable to include labor dollars for Account Managers or Community Service Managers/Supervisors in the conservation escrow budget. Funding should be included in non-escrow operation and maintenance (O&M).

21. It is reasonable to include dollars in the conservation escrow budget for the call center staff that are Energy Experts.

22. It is not appropriate to provide conservation escrow treatment for the Farm Rewiring Program. Funding should be included in non-escrow O&M.

23. It is not reasonable to provide conservation escrow treatment for the low-income assistance dollars contributed to the 2005 Wisconsin Act 141 (Act 141) statewide low-income programs. Funding should be included in non-escrow O&M.

24. The reasonable level of expensed conservation costs recoverable in rates for the 2013 test year is $8,662,412 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $8,191,041 plus an escrow adjustment of $470,626 to reflect the estimated overspent balance as of January 1, 2013, of $941,252, amortized over two years. The level for natural gas operations remains at $3,014,932, the same as that authorized in rate case docket 4220-UR-117.

25. A long-term range of 50 percent to 55 percent for NSPW's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

26. An appropriate target level for the test-year average common equity measured on a financial basis is 52.5 percent.

27. It is reasonable to explore further the target level for common equity in NSPW's next rate case.

28. A reasonable estimate of the debt-equivalent of NSPW's off-balance sheet obligations to be imputed into the financial capital structure for the test year is $4,614,306.

29. A reasonable financial capital structure for the test year consists of 52.50 percent equity, 43.96 percent long-term debt, 3.11 percent short-term debt, and 0.43 percent debt equivalence for off-balance sheet obligations.

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

31. It is reasonable to require NSPW to submit in its next rate proceeding, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

32. A reasonable regulatory capital structure for the test year consists of 52.37 percent equity, 44.49 percent long-term debt, and 3.14 percent short-term debt.

33. It is reasonable that NSPW's dividend restriction be based on the financial capital structure in this proceeding.

34. A reasonable interest rate for short-term borrowing through commercial paper is 0.53 percent for the test year.

35. A reasonable cost of the long-term debt issuance in 2012 is the actual yield to maturity of 3.746 percent.

36. A reasonable average embedded cost for long-term debt is 5.71 percent for the test year.

37. The rate of return on utility common stock equity of 10.40 percent established in NSPW's last rate case, docket 4220-UR-117, remains in place as it was not an issue addressed in this proceeding.

38. A reasonable weighted average composite cost of capital is 8.01 percent.

39. The electric revenue allocation and electric rates shown in Appendix B are reasonable.

40. The structure of the NSPW's voluntary green pricing program, marketed under the Windsource trademark, is reasonable.

41. It is reasonable to require NSPW to modify materials used to market the Windsource program in Wisconsin to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

42. It is reasonable for NSPW to continue to provide only a kilowatt (kW) block-based participation option for the Windsource program.

43. It is reasonable for the final form tariffs authorized in this proceeding to include an update to the Pg-1 tariff so as to preserve the grandfathering treatment for pre-January 1, 2012, vintage customers until a future base rate case proceeding.

44. It is reasonable to allocate the MGP allowance to the natural gas service rate classes on a net investment rate base methodology.

45. It is reasonable to authorize rates for natural gas service for NSPW as shown in Appendix C.

Conclusions of Law

The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, and 196.395 and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter a Final Decision authorizing NSPW 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 Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and its Business

NSPW is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas utility in Wisconsin. NSPW is engaged in providing electric service to approximately 251,000 retail customers in northwestern Wisconsin and the western tip of the Upper Peninsula of

Michigan. In addition, NSPW provides natural gas service to approximately 107,000 customers in Wisconsin and Michigan. NSPW is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel Energy).

Revenue Requirement

NSPW, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of NSPW's 2013 electric and natural gas utility operations. NSPW filed its natural gas case showing an estimated deficiency of $7.0 million, of which $5.3 million was associated with MGP cleanup costs. The company indicated it would limit its natural gas increase request to $5.3 million for MGP cleanup costs and forego the remaining $1.7 million. No parties objected to the proposal to limit the natural gas request to this single issue. Commission staff reviewed the gas utility forecasted test-year operations to determine that a rate decrease would not be needed, exclusive of NSPW's requested recovery of MGP clean-up costs. Commission staff's review resulted in no proposed adjustments to natural gas sales revenues or rate base and a reduction to operating expenses of $425,000 on a total company basis exclusive of any adjustment to MGP clean-up cost expenses. This adjustment grossed up for income taxes equates to a reduction to the natural gas deficiency of about $710,000, which is still less than the $1.7 million of which the company indicated it will forego requesting recovery. The Commission therefore finds it is reasonable to limit the scope of the natural gas rate increase request to the sole issue of MGP clean-up costs. Significant issues pertaining to electric operations and MGP clean-up costs are presented below.

Electric Fuel Costs

A reasonable test-year level of monitored fuel costs is $1,130.58 million, which reflects the cost of fuel as defined by Wis. Admin. Code § PSC 116.02. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 44,244,951 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of $25.55. Appendix D shows the monthly fuel costs to be used for monitoring purposes. The total fuel costs are based on indices for electric, natural gas, and heating oil prices as of November 15, 2012. It is reasonable to monitor NSP system's fuel costs using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

System Support Resources

NSPW requested that the Commission determine, in this proceeding, how SSR charges from the Midwest Independent Transmission System Operator, Inc. (MISO), will be treated in subsequent rate proceedings. MISO may assess SSR charges to NSPW if MISO requires another market participant to run a facility to support the transmission system even if the market participant desires to retire that facility. NSPW requested a determination that SSR charges be treated as a monitored fuel cost. SSR charges have never been assessed by MISO, but are expected to be assessed in the future. The Commission finds that there is not a sufficient basis, at this time, to determine how SSR charges are to be treated.

The Commission finds it reasonable to require Commission staff, investor-owned utilities and interested intervenors to work together after January 1, 2013, to address the SSR issue and for Commission staff to prepare a briefing memorandum outlining the parties' positions and alternatives for the Commission to consider.

2013 Fuel Cost Plan

NSPW requested that the Commission-authorized monitored fuel costs for 2013 be designated as the NSPW 2013 Fuel Cost Plan for purposes of Wis. Admin. Code § PSC 116.06(3). The Commission finds it reasonable to allow NSPW to use the Commission-authorized monitored fuel costs for NSPW's 2013 Fuel Cost Plan.

Annual Merit Pay Factors

NSPW's filed payroll forecast for the test-year included annual merit wage increases in 2012 of 2.0 percent for non-bargaining non-exempt employees, no increase for non-bargaining exempt employees, and 2.75 percent for all bargaining employees. NSPW's filing included wage increases in 2013 of 2.5 percent for all non-bargaining employees and 3.25 percent for all bargaining employees. Commission staff's forecasted payroll incorporated the 2012 actual wage increases as filed by NSPW and included 2013 wage increases of 3.25 percent for bargaining employees under contract and 1.7 percent for the non-bargaining employees based on inflation. The use of 1.7 percent for the non-bargaining employees resulted in a staff adjustment reducing test-year payroll O&M expense by $104,000.

The Commission finds that Commission staff's use of 2012 actual wage increases of 2.0 percent for non-bargaining non-exempt employees, no increase for non-bargaining exempt employees, 2.75 percent for all bargaining employees as well as forecasted 2013 wage increases of 3.25 percent for bargaining employees under contract and 1.7 percent for the non-bargaining employees based on inflation is reasonable in the development of test year payroll expense and related taxes. Incorporating these factors appropriately reflects the current economic conditions in Wisconsin.

Annual Incentive Plan Compensation

Xcel Energy must meet certain financial and operational goals in order for the current Annual Incentive Plan (AIP) to pay out incentive awards for the year to its non-bargaining employees. Incentive payments are in addition to annual base wage increases. According to the overall company performance component, which establishes the company's ability to pay, certain targeted earnings per share goals must be achieved by the company before the program will pay any awards. In addition, the final funding percentage will be determined by the Chief Executive Officer.

Commission staff reduced NSPW's 2013 payroll O&M expense for electric operations by $2,136,000 to eliminate the costs associated with the AIP. Elimination of costs associated with the incentive pay plan is consistent with the decisions made in the last round of rate cases for other large investor-owned utilities in which the costs associated with incentive pay plans were not included in revenue requirements.

NSPW maintains that the Commission should allow recovery of all or at least a portion of its AIP costs because it is important to compensate employees at a level that is comparable to the relevant market in order to ensure safe and reliable service at a reasonable cost. Because 97 percent of the goals relate to operational excellence, NSPW believes that 97 percent of the AIP costs should be recoverable.

In previous rate cases in which incentive adjustments have been contested, the Commission has excluded incentive plans from revenue requirement when such plans are based primarily on financial results (*e.g.*, prevailing stock price, earnings per share, or achieving a specified net income or return on investments, etc.). The Commission has determined that such plans most directly benefit the utility shareholders, and therefore the costs of the plans should not be borne by ratepayers. While the company has modified some of the elements of the AIP, it has not eliminated the financial performance of the company as one of the payout metrics. Specifically, earnings per share targets must be met before AIP funds can be paid, making it a system of compensation that occurs if and only if the company meets financial benchmarks.

In addition, while the operational goals of the AIP may benefit ratepayers, they also are intertwined in benefiting shareholders, making it difficult to separate which group benefits more.

Consistent with the other large-investor-owned utilities in Wisconsin, in which the costs associated with incentive pay plans are not included in revenue requirements, because of the continued tie to financial performance, the Commission finds it appropriate to exclude these AIP costs from revenue requirement.

U.S. Department of Energy Settlement Proceeds

In the last rate case proceeding in docket 4220-UR-117, the Commission authorized a one-time credit on customer bills for the first payment received in a settlement that was reached with the U.S. Department of Energy (DOE) relating to the partial breach of its contract to take spent nuclear fuel from Northern States Power Company-Minnesota's (NSPM) Monticello and Prairie Island nuclear generating plants. The settlement provides a mechanism for the NSP companies to recover nuclear spent fuel storage damages from January 1, 2009, through December 31, 2013. In 2012, the company received the second and third payments and expects to receive two additional payments at the end of 2013 and 2014, respectively. In this rate proceeding, NSPW proposed that the second and third payments received in 2012, including interest from the separate interest bearing account in which the funds are held, be returned to ratepayers by offsetting the 2013 electric revenue deficiency. The company proposed to allocate the settlement payments to the jurisdictions and customer classes in the same manner as the first payment, as approved by the Commission in docket 4220-UR-117. The proceeds from the second and third payments net of outside legal costs incurred in pursuit of the settlement included as a reduction to the 2013 electric revenue deficiency is $5,358,101 on a Wisconsin retail jurisdictional basis, and is for damages through December 31, 2011.

The Commission finds it reasonable to include the second and third payments from the DOE settlement net of outside legal costs incurred in pursuit of the settlement in the final electric revenue requirement approved in this proceeding. It is appropriate for the company to track, in a regulatory asset or liability account, the actual payments received, plus interest, less any unrecovered outside legal fees, and add or subtract the difference from the credit assumed in this case in future cases. It is appropriate for interest accrual on the sum of the second and third payments of $5,358,101 to terminate with the beginning of the 2013 test year.

Ashland Manufactured Gas Plant Site Cleanup

NSPW requested that the Commission include costs related to the clean-up of a former MGP site in Ashland in the 2013 test year. The company proposed that 2013 rates include estimates of expenses for the terrestrial and bay area clean-up. NSPW also requested that the Commission make an exception from its policy on the rate recovery of MGP clean-up costs. Specifically, NSPW requested that the amortization period be stretched from four or six years to ten years, that recovery begin immediately for expected costs rather than deferred to a later year, and that the company’s imbedded cost of debt for the unamortized clean-up expenses be included in rates. NSPW also proposed an alternative that involved allocating the revenue requirement impact to both electric and gas utilities instead of the current practice of allocating MGP costs to just the gas utility. Other intervenors proposed variations on NSPW's proposal.

The Commission must balance many concerns when it addresses rate recovery of MGP clean-up costs. In this case, the magnitude of the clean-up cost relative to the size of the customer base is significant. Applying the current policy to this particular site may cause financial harm to the company and cause significant rate shock to the utility's ratepayers. The Commission finds that making a limited exception to its policy on rate recovery of MGP clean-up costs is reasonable in this case. NSPW's request, as proposed, however, does not appropriately balance the concerns of the ratepayers against the financial health of the company.

It is reasonable that the net clean-up costs of the MGP clean-up for this site be amortized over a ten-year period, that estimates of the 2013 costs for clean-up at the terrestrial site, but not the bay area, be included in the 2013 test-year revenue requirement, and that the rates include 3 percent interest on the average balance of the unamortized clean-up costs. Lengthening the amortization period will help to mitigate the rate shock of large rate increases for this clean-up, while allowing immediate recovery of estimated expenses; and allowing the utility to recover some of the carrying costs of the clean-up will mitigate potential financial harm to NSPW.

Based upon the record in this proceeding, the Commission finds that it is not reasonable to deviate from the Commission's past practice of allocating MGP clean-up costs to just the gas utility. However, the Commission recognizes that neither the gas nor the electric utilities are the cause of this historic MGP liability. Accordingly, the Commission finds that is reasonable to review the practice of allocating the Ashland MGP clean-up costs as gas utility costs in the next rate proceeding to examine more fully whether such costs could or should be allocated to the electric utility, if appropriate, and to determine whether these clean-up costs should be included in the Interchange Agreement.

Energy Efficiency and Conservation Activities

The Commission's *Order*, dated August 30, 2011 (PSC REF#: 152745), conditionally approved NSPW's 2012 and 2013 voluntary utility energy efficiency programs. One of the requirements of the Order was to continue to work with the Commission and Focus on Energy staff to ensure NSPW offerings remain consistent with Focus on Energy offerings. The Commission determines that to date, the conditions of the *Order* have been met. NSPW's voluntary energy efficiency programs are reasonable, and it is appropriate to include their funding in the conservation escrow budget.

Conservation Budget and Escrow Adjustment

NSPW proposed a 2013 conservation escrow budget of $12,188,374, with $9,355,073 allocated to electric operations and $2,833,301 allocated to natural gas operations. Commission staff's analysis of conservation expenses included forecasting the over-spent balance in the conservation escrow at the beginning of the test year, reviewing the proposed test-year conservation expenditures, and reviewing the company's forecasted amortization expense associated with previously escrowed demand-side management expenditures. The reasonable levels of expensed conservation costs included in revenue requirement for the 2013 test year are $8,662,412 for electric operations and $3,014,932 for gas operations. The level for electric operations consists of a conservation budget of $8,191,786, plus an escrow adjustment of $470,626 to reflect the estimated overspent balance as of January 1, 2013, of $941,252, amortized over two years. Since the current natural gas rate case proceeding is limited to the single issue of MGP costs, the level of natural gas related expensed conservation costs included in revenue requirement for the 2013 test year remains at $3,014,932, the same as that authorized in rate case docket 4220-UR-117. Any adjustments to the conservation escrow balance for the natural gas operations will be addressed in a future rate proceeding.

Several adjustments were made to NSPW's proposed conservation escrow budget. In docket 5-BU-105 (PSC REF#: 168310), the Commission provided a definition of customer service conservation activities and services for which conservation escrow treatment is appropriate. Based on this definition, the Commission determines it appropriate to remove $114,000, $84,000 from electric operations and $29,640 from natural gas operations, for Account Managers. These NSPW employees devote less than 51 percent of their time to energy efficiency. Likewise, $156,912 is removed from the conservation escrow budget, $116,115 from electric operations and $40,797 from natural gas operations, for Community Service Managers/Supervisors because less than 51 percent of their time is devoted to energy efficiency. The Commission also finds that NSPW's Farm Rewiring Program does not meet the definition of customer service conservation because the primary purpose of this program is to assist customers in obtaining safe and reliable farm wiring and reduce levels of stray voltage, not energy efficiency. To reflect this, $752,129 is removed from the electric conservation escrow budget. Finally, low-income assistance dollars are removed from the conservation escrow, $210,683 from electric operations and $74,032 from natural gas operations. NSPW is required to contribute these low-income assistance dollars to Act 141 programs that provide both weatherization and bill payment assistance to low income customers. Because the program provides for bill payment assistance in addition to weatherization, and because the contribution level remains the same every year, its funding is not appropriate for conservation escrow treatment.

NSPW originally indicated that it has about 400 call center staff that devote about 6 percent of their time to energy efficiency. In response to a Commission staff data request, NSPW clarified that in 2011 it developed an Energy Experts team. This Energy Experts team consists of call center staff that is specially trained to provide residential customers detailed energy efficiency information. NSPW indicates that these Energy Experts devote 100 percent of their time to energy efficiency issues. The Commission finds is reasonable to allow conservation escrow treatment for the Energy Expert staff.

Summary of Income Statement

In addition to the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to NSPW's filed electric operating income statement are appropriate. Accordingly, the estimated Wisconsin retail electric utility operating income statement at present rates for the 2013 test year, which is considered reasonable for the purpose of determining the electric revenue requirement in this proceeding, is as follows:

	Retail Electric (000's)
Operating Revenues	
Sales	$583,411
Other Operating Revenues	1,928
Total Operating Revenues	$585,339
Operating Expenses	
Production Expense	$367,614
Transmission Expenses	(8,819)
Distribution Expenses	21,683
Customer Accounts Expenses	8,913
Customer Service & Sales Expenses	11,888
Administrative & General Expenses	36,481
Total Operation & Maintenance Expenses	$437,760
Depreciation Expense	63,503
Amortization Expense	(125)
Taxes Other Than Income Taxes	21,856
State Income Taxes	1,600
Federal Income Taxes	4,742
Deferred Income Taxes – Net	10,379
Investment Tax Credits Restored	(637)
Total Operating Expenses	$539,078
Chippewa Flambeau Improvement Company Income	39
Net Operating Income	$ 46,300

Average Net Investment Rate Base

Allowance for Funds Used During Construction

NSPW requested to accrue excess Allowances for Funds Used During Construction (AFUDC) on all Construction Work in Progress (CWIP), which is consistent with the accrual methodology used by the other Wisconsin utilities.

Consistent with the calculation of AFUDC for other Wisconsin utilities, it is appropriate to permit NSPW to accrue AFUDC on all CWIP at the weighted average cost of capital instead of at the Federal Energy Regulatory Commission (FERC) AFUDC rate. This rate treatment allows NSPW to recover the full carrying costs from retail customers and is appropriate as long as the accrual of excess AFUDC above the FERC-calculated AFUDC does not flow though the Interchange Agreement, either from or to NSPW.

Summary of Average Net Investment Rate Bases

The estimated Wisconsin retail electric utility average net investment rate base for the 2013 test year, which is considered reasonable for the purpose of determining the electric revenue requirement in this proceeding, is as follows:

	Retail Electric (000's)
Utility Plant in Service	$1,911,536
Less: Accumulated Reserve for Depreciation	895,913
Net Utility Plant	$1,015,623
Add: Fuel Inventory	9,701
Materials and Supplies	4,256
Investments in Associated Companies	537
Less: Accumulated Deferred Income Taxes	228,067
Customer Advances – net of tax	13,448
Average Net Investment Rate Base	$788,602

***Pro Forma* Rate of Return**

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2013, results in a rate of return on average net investment rate base of 5.87 percent for Wisconsin retail electric utility operations.

Financial Capital Structure and Dividend Restriction

A reasonable long-term range for NSPW's common equity ratio, on a financial basis, is 50 to 55 percent common equity. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing NSPW at a given time. An appropriate target level for the test-year average common equity measured on a financial basis is 52.50 percent. This target level shall be further examined in NSPW's next rate proceeding.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. Detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent is necessary for the Commission to make an independent judgment regarding NSPW's financial capital structure. This information is most readily available from NSPW and must be provided as part of its next rate case application. The information shall include, at a minimum, the following information:

1. the minimum annual lease and purchased power agreement obligations;
2. the method of calculation, along with the calculated amount of the debt equivalent; and
3. supporting documentation, including all reports, correspondence, and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent to the extent available, and publicly available documentations when S&P and other major credit rating agencies' documentation is not available.

For the test year, the Commission finds that it is reasonable to impute $4,614,306 of debt equivalent associated with NSPW's off-balance sheet obligations. Incorporating the above off-balance sheet debt equivalents and other Commission determinations, NSPW's financial capital structure for the test year will consist of 52.50 percent equity, 43.96 percent long-term debt, 3.11 percent short-term debt, and 0.43 percent debt equivalence for off-balance sheet obligations.

Assessing the reasonableness of NSPW's capital structure depends upon three important principles. First, capital structure decisions must be based on NSPW's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility to NSPW and to the Commission to allow proper utility investment now and in the future. Third, the dividend policy of NSPW should be similar to typical electric utility dividend practices as long as NSPW is below the estimated test-year common equity ratio.

In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. Consequently, NSPW may not pay dividends, including pass-through of subsidiary dividends, in excess of the $31,189,664 forecasted in this case, if its actual average common equity ratio, on a financial basis, is or will fall below the test-year authorized level of 52.50 percent.

Ten-Year Financial Forecast

NSPW's ten-year financial forecast is useful to the Commission and shall be submitted in future rate cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, Commission staff deducted from the utility's equity the non-utility investments or other equity adjustments on which ratepayers should not pay an equity return for ratemaking purposes. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consist of 52.37 percent equity, 44.49 percent long-term debt, and 3.14 percent short-term debt.

Short-Term Debt

NSPW's test-year capital structure contains approximately $33,144,000 of short-term debt. The interest rate associated with the short-term indebtedness is the commercial paper rate.

A reasonable estimate of the average cost of short-term commercial paper for NSPW for the test year is 0.53 percent. This forecast is based on the average of test year commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter, adjusted by 33 basis points to reflect the spread between A-1/P-1 and A-2/P-2 rated commercial paper yields. This is a reasonable and objective method of determining short-term debt costs.

Long-Term Debt

NSPW's test-year long-term debt included an issuance of 30-year debt aggregating $100,000,000 principal amount forecasted for issuance in 2012. On October 10, 2012, NSPW issued the debt with a coupon rate of 3.7 percent and a yield to maturity of 3.746 percent. A reasonable interest rate for the debt is 3.746 percent. The resulting embedded cost of long-term debt is 5.71 percent for the test year.

Return on Common Equity

The Commission previously determined, in docket 4220-UR-117, a 10.40 percent return on utility common equity for NSPW to be reasonable. As rate of return on common equity was not an issue addressed in this proceeding, the Commission determines that this return on equity shall remain in place until addressed in a subsequent rate case proceeding. Using a 10.40 percent return on equity, NSPW's average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$552,337	52.37%	10.40%	5.45%
Long-Term Debt	469,183	44.49%	5.71%	2.54%
Short-Term Debt	33,144	3.14%	0.53%	0.02%
Total Utility Capital	$1,054,664	100.00%		8.01%

The weighted cost of capital of 8.01 percent is reasonable for NSPW for the test year. It generates an economic cost of capital of 11.66 percent and a pre-tax interest coverage ratio of 4.56 times on the regulatory capital structure.

Rate of Return on Rate Base

The 8.01 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of NSPW's average net investment rate base plus CWIP for the test year is 93.49 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. Accordingly, the rate of return on average Wisconsin retail electric utility net investment rate base, which is reasonable for the purpose of determining just and reasonable rates in this proceeding, is as follows:

	Retail Electric
Cost of Capital	8.01%
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	93.49%
Percent Return Requirement Applicable to Net Investment Rate Base	8.57%

Revenue Requirement

On the basis of the findings in this Final Decision, a $35,532,000 increase in Wisconsin retail electric utility revenues is reasonable for the purpose of determining reasonable and just rates in this proceeding and is computed as follows:

	Retail Electric (000's)
Pro Forma Return on Average Net Investment Rate Base at Present Rates	5.87%
Required Return on Average net Investment Rate Base	8.57%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	2.70%
Average Net Investment Rate Base (000's)	$788,602
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	$21,283
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$35,532

Electric Cost-of-Service

Both NSPW and Commission staff submitted the results of several cost-of-service studies. The two major electric cost-of-service issues contested in this proceeding are the allocation of production capacity costs and the allocation of distribution system costs. The allocation of these costs significantly affects the cost responsibility for providing electric service.

The Commission routinely considers electric cost-of-service studies as a guide along with other factors in its decisions regarding the allocation of revenue responsibility. In this proceeding, the Commission determines that it is reasonable to continue its past practice of relying on the results of more than one cost-of-service study, as well as other factors for determining an appropriate allocation of the revenue responsibility.

Electric Revenue Allocation

Allocating the increase in NSPW's revenue requirement for the provision of electric service was also a significant contested issue in this proceeding. Both NSPW and Commission staff submitted a comprehensive allocation of the proposed electric revenue increase. NSPW proposed a very narrow range of increases within 0.2 percent of its overall 6.7 percent electric increase for all of the major customer classes. Commission staff's alternative was similar, but included a slightly wider range of increase within 0.5 percent of its overall 5.65 percent electric increase, except the medium commercial and industrial classes get approximately 0.9 percent below the overall average.

The Commission routinely considers factors other than cost-of-service studies such as bill impacts, existing relationships between rate classes, and the overall magnitude of the revenue change, in its decisions regarding the allocation of revenue responsibility. The results of the cost studies introduced in this case support various revenue allocations. The Commission determines that a reasonable allocation of the electric revenue increase is a 7.2 percent increase for the residential classes, a 5.8 percent increase for the medium commercial and industrial classes, a 5.0 percent increase for the large commercial and industrial classes and a 6.8 percent increase for the lighting and miscellaneous classes, as adjusted for the final revenue requirement.

Commissioner Callisto dissents.

Electric Rate Design

NSPW initially proposed a rate design that included increases in energy charges, demand charges and lighting charges, for the various customer classes. NSPW initially proposed similar percentage increases for both the energy and demand charges. That proposal also increases the voltage discounts for the transmission level customers and increases high load factor credits. Commission staff's alternative rate design included similar percentage increases for both the energy charges and demand charges, but included lower increases in the high load factor credit and no increase for the voltage discounts.

Wisconsin Industrial Energy Group (WIEG) argued that the rate design for the Cg-9, Cp-1 and the RTP-1 classes should include greater than average increases for the demand charges and less than average increases for the energy charges. WIEG also supported NSPW's proposal to increase the voltage discounts for the transmission level customers and increase high load factor credits. NSPW responded by introducing a compromise proposal that included demand charge increases half way between WIEG's proposal and the Commission staff's proposal and energy charge increases that are lower than the average increase percentage for these classes. This proposal also included the increases to the transmission voltage discounts and increases to the high load factor credits that were part of NSPW's initial proposal. The Commission determines that NSPW's compromise proposal for changing the demand and energy charges affecting all of the commercial and industrial customers, and its proposal to increase the transmission voltage discounts and high load factor energy charge credits affecting the large commercial and industrial customers, are reasonable.

Commissioner Callisto dissents on the authorization of the higher transmission voltage discounts.

The Commission also finds NSPW's electric rate design and the changes in energy and lighting charges for the residential, small commercial, lighting and miscellaneous classes, adjusted for the final revenue requirement, are reasonable. The authorized electric rates are shown in Appendix B.

Act 141 in Electric Rates

Act 141 contains a limitation on how much the "large energy customers"[1] can pay in rates for these Act 141 costs. Act 141 requires the large energy customer "capped rates" increase each year by the lesser of the prior year Consumer Price Index (CPI) or the utility's change in revenue from the prior year. Both NSPW and Commission staff agree that the increase in the "capped rates" should be 3.2 percent for 2013, which reflects inflation based on the prior year CPI. Both NSPW and Commission staff proposed rate factors representing the Act 141 costs in electric rates for the non-large energy customers that are essentially the same except for differences between NSPW's and Commission staff's electric sales forecast and a calculation error in the inflation rate NSPW initial used.

The correct reflection of the capped Act 141 costs in the RTP-1 rates was a rate issue that was controversial, but the record was somewhat unclear. NSPW filed a rate and revenue analysis in Ex.-NSPW-Dahl-2 that did not show an explicit amount for the capped Act 141 costs in the RTP-1 rates. Under this approach, it is assumed that the Act 141 costs are in the based rates for the RTP-1 class. Commission staff filed a rate and revenue analysis in Ex.-PSC-Albrecht-2r that included an explicit amount for Act 141 costs that the RTP-1 rate class is required to pay under Wisconsin Statutes. This was a change from how it was handled in NSPW's last rate case. WIEG argued that NSPW's approach was correct. Determining the correct approach on this issue is difficult based upon the record in this case. This issue should be fully vetted in NSPW's next rate case. It is reasonable to maintain the status quo and accept

[1] A "large energy customer" is defined as a customer whose facility consumes at least 1,000 kilowatts of electricity per month or at least 10,000 decatherms of natural gas per month, and who is billed at least $60,000 in a month for electric and gas services. All of the utility billing accounts of a company are considered to determine if the company qualifies as a large energy customer. A company that qualifies will have all of its accounts treated as a large energy customer for billing purposes, despite the accounts being served under different tariffs.

NSPW's approach of not showing any explicit capped Act 141 costs in the rate and revenue analysis for the RTP-1 class.

Windsource Program

Order Point 33 of the *Final Decision* in docket 4220-UR-117, stated that "a full analysis shall be required in NSPW's next rate case on the issue of the company's Windsource voluntary green pricing program." During that proceeding, the Commission expressed concerns regarding the structure and pricing of the Windsource program due to the way in which renewable energy is treated under the Interchange Agreement.

Typically, when utility customers elect to participate in green energy pricing programs, the utility purchases more renewable energy than it is otherwise required to purchase. However, because the Interchange Agreement already requires NSPW to purchase more renewable energy than is required to comply with Wisconsin's renewable portfolio standard, a customer's participation in the Windsource program does not lead to a greater amount of renewable energy on the NSPW system than would have existed otherwise. NSPW retires Renewable Energy Credits not used for compliance with Wisconsin's renewable portfolio standard in order to satisfy renewable energy purchases through Windsource.

The Commission finds the overall structure of NSPW's Windsource program to be reasonable. While NSPW does not purchase additional renewable energy as a direct result of a person signing up for Windsource, the program still offers value to customers seeking ways in which to "green" their energy consumption. However, due to the potential for customer confusion, NSPW shall modify materials used to market the Windsource program in Wisconsin to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

Commission staff also proposed that NSPW modify Windsource to allow customers the option of buying a percentage of their energy from the program. NSPW believes that this change to the program would be cost prohibitive. Given the information available in the record, the Commission finds it reasonable for NSPW to continue to provide only a kW block-based participation option for the Windsource program. However, NSPW shall provide in its next base rate case, additional information regarding the billing system costs the company claims would be associated with providing a percentage-based participation option for the Windsource program.

Net Metering

NSPW did not propose any changes to its Pg-1 net metering tariff. Based on the understanding that the company wished to leave the Pg-1 net energy billing tariff as is, and continue grandfathering pre-January 1, 2012, vintage customers until a future proceeding, Commission staff proposed that final form tariffs authorized in this proceeding should include an update to the Pg-1 tariff so as to preserve the grandfathering treatment for pre-January 1, 2012, vintage customers until a future base rate case proceeding. The Commission finds Commission staff's proposed treatment of the Pg-1 tariff to be reasonable.

Electric Tariff Changes

NSPW proposed changes to its electric Distribution Extension Allowances that are shown in Ex.-NSPW-Marx-1, Schedule 6. There were no objections to these changes. The distribution extension allowances are part of NSPW's electric rule and regulation tariffs. The Commission finds it reasonable to approve these proposed changes to NSPW's electric rule and regulation tariffs.

NATURAL GAS COST-OF-SERVICE STUDIES AND RATES

Natural Gas Cost-of-Service Studies

The natural gas rate increase will provide for the allowed incremental MGP costs of $2,717,362. This singular cost allowance did not necessitate a cost-of-service analysis of NSPW's overall costs of providing natural gas service. For purposes of this proceeding, the costs allocation and rate recovery was limited to MGP costs. Several cost allocation methodologies were identified and considered appropriate; however, the Commission determines that final rates for natural gas service shall be based on the net investment rate base cost allocation methodology.

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for NSPW in Appendix C of this Final Decision will provide for the incremental cost recovery of the allowed MGP costs of $2,717,362. This represents an increase of 6.42 percent in margin rates and an increase of 2.53 percent in total natural gas sales revenues. Margin rates exclude natural gas costs.

Authorized rates as set forth in Appendix C include a rate "adjustment" over present rates that were determined on a volumetric unit basis given estimated 2013 test-year sales and the MGP cost allocations as discussed above. Summaries of the rate impacts on a service rate class are shown in Appendix C.

As shown in Appendix C, the authorized natural gas rates result in a range of increases in the charges to the various service rate classes. The percentage rate decrease to any individual customer will not necessarily equal the overall percentage decrease to the associated service rate class, but will depend on the specific usage level of the customer.

Appendix C also shows some typical natural gas bills for residential service, comparing existing rates with new rates, including the cost of natural gas.

Order

1. This Final Decision takes effect one day after the date of mailing.

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect January 1, 2013, provided that the utility files these rates and tariff provisions with the Commission and places them in all of the utility's offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

3. NSPW may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B and C. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

4. The electric fuel costs in Appendix D shall be used for monitoring of the NSP system's 2013 fuel costs, pursuant to Wis. Admin. Code § PSC 116.06(3).

5. NSPW shall not include labor dollars in the conservation escrow budget for Account Managers or Community Service Managers/Supervisors.

6. The Farm Rewiring Program shall not receive escrow treatment.

7. Low-income assistance dollars required by Act 141 to be contributed to statewide low-income programs shall not receive escrow treatment.

8. NSPW shall record annual conservation accrual amounts of $8,662,412 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $8,191,041 plus an escrow adjustment of $470,626 to reflect the estimated overspent balance as of January 1, 2013, of $941,252, amortized over two years. The level for natural gas operations remains at $3,014,932, the same as that authorized in rate case docket 4220-UR-117.

9. NSPW shall maintain 50 to 55 percent common equity on a financial basis in its capital structure.

10. The appropriate target level for NSPW's common equity shall be further explored in the company's next rate case.

11. NSPW shall submit a ten-year financial forecast in its next rate case.

12. NSPW shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at a minimum: (1) the minimum annual lease and purchase power agreement obligations; (2) the method of calculation, along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies' documentation is not available.

13. NSPW shall not pay dividends, including pass-through of subsidiary dividends, in excess of $31,189,664, if its actual average common equity ratio, on a financial basis, is or will fall below the test year authorized level of 52.50 percent.

14. NSPW shall modify materials used to market the Windsource program in Wisconsin so as to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

15. In its next base rate case, NSPW shall provide additional information regarding the billing system costs the company claims would be associated with providing a percentage-based participation option for the Windsource program.

16. Jurisdiction is retained.

Dissent and Concurrence

Commissioner Callisto dissents in part, concurs, and writes separately (attached).

Dated at Madison, Wisconsin, this 27th day of December, 2012.

By the Commission:

Sandra J. Paske

Sandra J. Paske
Secretary to the Commission

SJP:CCS:cmk:DL:00611941

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. 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.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing 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 petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of mailing of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of mailing of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission mailed its original decision.[2] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

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

Revised: December 17, 2008

[2] *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

SERVICE LIST

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.

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(Not a party, but must be served)
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NORTHERN STATES POWER COMPANY (WISCONSIN)

SUMMARY OF ELECTRIC REVENUE
FOR TEST YEAR 2013

INDIVIDUAL RATE CLASSES	PRESENT REVENUES	AUTHORIZED REVENUES	DOLLAR INCREASE	PERCENT INCREASE
Rg-1 (Residential)	$ 200,189,419	$ 214,305,579	$ 14,116,160	7.05%
Rg-2 (Residential - Optional Time-of-Day)	11,070,696	11,862,113	791,417	7.15%
Fg-1 (Farm Service)	9,624,585	10,341,693	717,108	7.45%
Cg-6 (Optional Off-Peak Service -- Res.)	85,932	91,589	5,657	6.58%
S-1 (Automatic Protective Lighting -- Res.)	438,673	468,403	29,730	6.78%
Cg-1 (Small General - Optional Time-of-Day)	454,208	487,166	32,958	7.26%
Cg-2 (Small General Non-TOD)	42,534,695	45,608,668	3,073,973	7.23%
S-1 (Automatic Protective Lighting -- Com.)	580,166	619,537	39,371	6.79%
Ms-6 (Underground Area Lighting - Private)	31,576	33,725	2,149	6.81%
Cg-5 (General Service TOD)	84,367,437	89,258,322	4,890,885	5.80%
Cg-6 (Optional Off-Peak Service -- C&I)	225,034	240,552	15,518	6.90%
Cp-2 (Peak Controlled Non-TOD)	3,127,321	3,312,569	185,249	5.92%
Cg-9 (Large General TOD)	157,496,035	165,563,370	8,067,335	5.12%
DS-1 (Military Fac. Distrib. Service)	629,430	643,234	13,804	2.19%
Cp-1 (Peak Controlled Service)	54,126,007	56,777,630	2,651,622	4.90%
RTP-1 (Real-Time Pricing)	12,718,600	13,237,016	518,416	4.08%
Ms-2 (Company Owned Street Lighting)	3,309,285	3,534,299	225,014	6.80%
Ms-3 (Cust. Owned Incand./Fluor. Lighting)	6,971	7,445	474	6.80%
Ms-4 (Customer Owned Lighting)	468,570	500,767	32,197	6.87%
Ms-6 (Underground Area Lighting - Public)	345,477	368,983	23,506	6.80%
Ms-7 (Metered - Customer Owned Lighting)	125,613	133,940	8,327	6.63%
Mp-1 (Municipal Water Pumping)	1,096,849	1,179,235	82,386	7.51%
Mz-3 (Fire Siren Service)	4,878	4,878	0	0.00%
VRE (Voluntary Renewable Energy - Windsource)	184,950	184,950	0	0.00%
Pg-2 (Parallel Generation Service)	0	0	0	0.00%
TOTAL ELECTRIC RETAIL SALES	583,242,407	618,765,663	35,523,256	6.09%
Interdepartmental Sales	168,592	177,816	9,224	5.47%
TOTAL ELECTRIC	**$ 583,410,999**	**$ 618,943,479**	**$ 35,532,480**	**6.09%**

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
RESIDENTIAL SERVICE, Rg-1			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Water Heating Meter Chg. (per Month per Meter)		$2.00	$2.00
Load Management Credit (per Month):			
Water Heating		$2.00	$2.00
Air Conditioning (Summer Only)		$6.00	$6.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
RESIDENTIAL TOD SERVICE, Rg-2			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh):	On-Peak (Summer)	21.2320 ¢	22.8420 ¢
	On-Peak (Non-Summer)	19.6070 ¢	21.0940 ¢
	Off-Peak (Summer)	5.4210 ¢	5.8390 ¢
	Off-Peak (Non-Summer)	5.4210 ¢	5.8390 ¢
FARM SERVICE, Fg-1			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Load Management Credit (per Month):			
Water Heating		$2.00	$2.00
Air Conditioning (Summer Only)		$6.00	$6.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
SMALL GENERAL SERVICE, Cg-2			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Un-metered Cust. Charge (per Month):	Single-Phase	$4.50	$4.50
	Three-Phase	$6.50	$6.50
Water Heating Meter Chg. (per Month per Meter)		$2.00	$2.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0630 ¢	0.0650 ¢
SMALL GENERAL TOD SERVICE, Cg-1			
Customer Charge (per Month)	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh):	On-Peak (Summer)	21.2320 ¢	22.8420 ¢
		19.6070 ¢	21.0940 ¢
	Off-Peak (Summer)	5.4210 ¢	5.8390 ¢
		5.4210 ¢	5.8390 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
GENERAL SERVICE, Cg-5			
Customer Charge (per Month):		$30.00	$30.00
Demand Charges (per kW):	Secondary (Summer)	$11.25	$11.95
	Secondary (Non-Summer)	$9.25	$9.95
	Primary (Summer)	$10.70	$11.36
	Primary (Non-Summer)	$8.74	$9.40
Energy Charge (per kWh)	Summer	6.0050 ¢	6.3275 ¢
	Non-Summer	5.4640 ¢	5.7577 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0480 ¢	0.0480 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.55	$0.59
[Discounts Reflected Above]	Non-Summer	$0.51	$0.55
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.8000 ¢	0.9000 ¢
PEAK CONTROLLED SERVICE, Cp-2			
Customer Charge (per Month):		$40.00	$40.00
Demand Charges (per kW):			
Firm Demand:	Secondary (Summer)	$11.25	$11.95
	Secondary (Non-Summer)	$9.25	$9.95
	Primary (Summer)	$10.70	$11.36
	Primary (Non-Summer)	$8.74	$9.40
Controlled Demand:	Secondary (Summer)	$6.54	$7.05
	Secondary (Non-Summer)	$6.54	$7.05
	Primary (Summer)	$6.08	$6.56
	Primary (Non-Summer)	$6.08	$6.56
Energy Charge (per kWh)	Summer	6.0050 ¢	6.3275 ¢
	Non-Summer	5.4640 ¢	5.7577 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0230 ¢	0.0230 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.55	$0.59
[Discounts Reflected Above]	Non-Summer	$0.51	$0.55
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.900 ¢	0.900 ¢
OPTIONAL OFF-PEAK SERVICE, Cg-6			
Customer Charge (per Month):	Single-Phase	$4.00	$4.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh)	Secondary (Summer)	4.9780 ¢	5.3720 ¢
	Secondary (Non-Summer)	4.9780 ¢	5.3720 ¢
	Primary (Summer)	4.8784 ¢	5.2650 ¢
	Primary (Non-Summer)	4.8784 ¢	5.2650 ¢
Non-Authorized Use Charge (per kWh)		21.9150 ¢	22.4020 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
LARGE GENERAL TOD SERVICE, Cg-9			
Customer Charge (per Month):	Mandatory	$155.00	$155.00
	Optional	$55.00	$55.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$9.75	$10.45
	Secondary (Non-Summer)	$7.75	$8.45
	Primary (Summer)	$9.56	$10.24
	Primary (Non-Summer)	$7.60	$8.28
	Trans. Transformed (Sum.)	$9.12	$9.72
	Tr. Transform. (Non-Sum.)	$7.25	$7.86
	Transmission (Summer)	$9.07	$9.67
	Transmission (Non-Sum.)	$7.21	$7.82
Customer Demand Charges (per kW):	Secondary	$1.30	$1.39
	Primary	$0.97	$1.04
	Trans. Transformed	$0.55	$0.59
	Transmission	$0.00	$0.00
Energy Charge (per kWh):	On-Peak (Summer)	7.6960 ¢	8.0210 ¢
	On-Peak (Non-Summer)	6.9420 ¢	7.2350 ¢
	Off-Peak (Summer)	4.5380 ¢	4.7300 ¢
	Off-Peak (Non-Summer)	4.5380 ¢	4.7300 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0370 ¢	0.0370 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	6.50%	7.00%
	Transmission	7.00%	7.50%
Voltage Discounts = [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.19	$0.21
	Primary (Non-Summer)	$0.15	$0.17
	Trans. Transformed (Sum.)	$0.63	$0.73
	Tr. Transform. (Non-Sum.)	$0.50	$0.59
	Transmission (Summer)	$0.68	$0.78
	Transmission (Non-Sum.)	$0.54	$0.63
Customer (per kW):	Primary	$0.33	$0.35
	Trans. Transformed	$0.75	$0.80
	Transmission	$1.30	$1.39
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.8000 ¢	0.9000 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PEAK CONTROLLED TOD SERVICE, Cp-1			
Customer Charge (per Month):	Demands >200 kW	$175.00	$175.00
	Demands ≤ 200 kW	$75.00	$75.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$9.75	$10.45
	Secondary (Non-Summer)	$7.75	$8.45
	Primary (Summer)	$9.56	$10.24
	Primary (Non-Summer)	$7.60	$8.28
	Trans. Transformed (Sum.)	$9.12	$9.72
	Tr. Transform. (Non-Sum.)	$7.25	$7.86
	Transmission (Summer)	$9.07	$9.67
	Transmission (Non-Sum.)	$7.21	$7.82
Customer Demand Charges (per kW):	Secondary	$1.30	$1.39
	Primary	$0.97	$1.04
	Trans. Transformed	$0.55	$0.59
	Transmission	$0.00	$0.00
Controlled Demand Charges (per kW):	Secondary (Summer)	$5.04	$5.55
	Secondary (Non-Summer)	$5.04	$5.55
	Primary (Summer)	$4.94	$5.44
	Primary (Non-Summer)	$4.94	$5.44
	Trans. Transformed (Sum.)	$4.72	$5.16
	Tr. Transform. (Non-Sum.)	$4.72	$5.16
	Transmission (Summer)	$4.71	$5.14
	Transmission (Non-Sum.)	$4.70	$5.14
Energy Charge (per kWh):	On-Peak (Summer)	7.6960 ¢	8.0210 ¢
	On-Peak (Non-Summer)	6.9420 ¢	7.2350 ¢
	Off-Peak (Summer)	4.5380 ¢	4.7300 ¢
	Off-Peak (Non-Summer)	4.5380 ¢	4.7300 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0310 ¢	0.0310 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	6.50%	7.00%
	Transmission	7.00%	7.50%
Voltage Discounts [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.19	$0.21
	Primary (Non-Summer)	$0.15	$0.17
	Trans. Transformed (Sum.)	$0.63	$0.73
	Tr. Transform. (Non-Sum.)	$0.50	$0.59
	Transmission (Summer)	$0.68	$0.78
	Transmission (Non-Sum.)	$0.54	$0.63
Customer (per kW):	Primary	$0.33	$0.35
	Trans. Transformed	$0.75	$0.80
	Transmission	$1.30	$1.39
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.800 ¢	0.900 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES

MILITARY FACILITY DISTRIBUTION SERVICE, DS-1

Distribution Service Charge (per kW)		$4.56	$4.66

EXPERIMENTAL REAL TIME PRICING, RTP-1

Customer Charge (per Month)		$300.00	$300.00
Contract Demand Charges (per kW):	Secondary	$9.09	$9.12
	Primary	$8.91	$8.93
	Trans. Transformed	$8.50	$8.48
	Transmission	$8.45	$8.44
Distribution Demand Charges (per kW):	Secondary	$1.30	$1.39
	Primary	$0.97	$1.04
	Trans. Transformed	$0.55	$0.59
	Transmission	$0.00	$0.00
Energy Charges (per kWh):		Authorized Hourly Energy Prices included in the table below	
Energy Voltage Discounts (per kWh):	Primary	0.100 ¢	0.100 ¢
	Trans. Transformed	0.331 ¢	0.376 ¢
	Transmission	0.356 ¢	0.403 ¢
Limited Energy Surcharge (per kWh)		10.9500 ¢	11.6500 ¢
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.7000 ¢	0.9000 ¢

Energy Chgs. $ per kWh	Day Types							
	1	2	3	4	5	6	7	8
12 am - 6 am	0.05502	0.04995	0.04744	0.04288	0.04047	0.03605	0.03571	0.03395
6 am - 9 am	0.09550	0.07812	0.06412	0.06501	0.06210	0.04680	0.04636	0.03934
9 am - 12 pm	0.24700	0.17101	0.10770	0.08563	0.07065	0.06046	0.04961	0.04285
12 pm - 6 pm	0.41163	0.27233	0.15836	0.09828	0.07065	0.06046	0.04961	0.04285
6 pm - 9 pm	0.29765	0.22167	0.13303	0.08741	0.07065	0.06046	0.04961	0.04285
9 pm - 12 pm	0.09297	0.07526	0.06755	0.06007	0.04971	0.04448	0.04072	0.03821

AUTOMATIC PROTECTIVE LIGHTING, S-1

Monthly Charges (per Unit):		
175 Watt MV Lamps (Closed)	$8.51	$9.09
250 Watt MV Lamps (Closed)	$11.33	$12.10
400 Watt MV Lamps (Closed)	$15.24	$16.28
70 Watt HPS Lamps	$6.08	$6.49
100 Watt HPS Lamps	$7.40	$7.90
150 Watt HPS Lamps	$8.93	$9.54
250 Watt HPS Lamps	$12.11	$12.93
400 Watt HPS Lamps	$17.31	$18.49

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-2		
Monthly Charges (per Lamp):		
Overhead:		
175 Watt MV Lamps (Closed)	$12.43	$13.28
250 Watt MV Lamps (Closed)	$14.16	$15.12
400 Watt MV Lamps (Closed)	$17.51	$18.70
70 Watt HPS Lamps	$10.21	$10.90
100 Watt HPS Lamps	$11.13	$11.89
150 Watt HPS Lamps	$12.40	$13.24
250 Watt HPS Lamps	$15.42	$16.47
400 Watt HPS Lamps	$20.05	$21.41
Underground:		
175 Watt MV Lamps (Closed)	$18.21	$19.45
250 Watt MV Lamps (Closed)	$19.82	$21.17
70 Watt HPS Lamps	$15.28	$16.32
100 Watt HPS Lamps	$16.21	$17.31
150 Watt HPS Lamps	$17.48	$18.67
250 Watt HPS Lamps	$20.74	$22.15
400 Watt HPS Lamps	$25.12	$26.83
Decorative Underground:		
100 Watt HPS Lamps	$34.65	$34.65
150 Watt HPS Lamps	$36.21	$36.21
250 Watt HPS Lamps	$39.36	$39.36
400 Watt HPS Lamps	$43.94	$43.94
Maintenance Option:		
100 Watt HPS Lamps	$8.28	$8.84
150 Watt HPS Lamps	$9.88	$10.55
250 Watt HPS Lamps	$13.02	$13.91
400 Watt HPS Lamps	$17.60	$18.80

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
CUSTOMER OWNED STREET LIGHTING, Ms-4		
Monthly Charges (per Lamp):		
Group I - Energy and Maintenance:		
175 Watt MV Lamps (Closed)	$6.91	$7.38
250 Watt MV Lamps (Closed)	$8.49	$9.07
400 Watt MV Lamps (Closed)	$12.05	$12.87
700 Watt MV Lamps (Closed)	$19.06	$20.36
50 Watt HPS Lamps	$4.19	$4.47
70 Watt HPS Lamps	$4.66	$4.98
100 Watt HPS Lamps	$5.56	$5.94
150 Watt HPS Lamps	$6.60	$7.05
250 Watt HPS Lamps	$9.66	$10.32
400 Watt HPS Lamps	$13.24	$14.14
Group I - Energy and Maintenance (No Paint):		
175 Watt MV Lamps (Closed)	$6.66	$7.13
250 Watt MV Lamps (Closed)	$8.24	$8.82
400 Watt MV Lamps (Closed)	$11.80	$12.62
700 Watt MV Lamps (Closed)	$18.81	$20.11
50 Watt HPS Lamps	$3.94	$4.22
70 Watt HPS Lamps	$4.41	$4.73
100 Watt HPS Lamps	$5.31	$5.69
150 Watt HPS Lamps	$6.35	$6.80
250 Watt HPS Lamps	$9.41	$10.07
400 Watt HPS Lamps	$12.99	$13.89
Group II - Energy Only:		
100 Watt MV Lamps (Closed)	$2.69	$2.87
175 Watt MV Lamps (Closed)	$4.30	$4.59
400 Watt MV Lamps (Closed)	$9.48	$10.12
700 Watt MV Lamps (Closed)	$16.18	$17.28
35 Watt HPS Lamps	$0.90	$0.96
50 Watt HPS Lamps	$1.30	$1.39
70 Watt HPS Lamps	$1.72	$1.84
100 Watt HPS Lamps	$2.59	$2.77
150 Watt HPS Lamps	$3.99	$4.26
200 Watt HPS Lamps	$5.07	$5.41
250 Watt HPS Lamps	$6.16	$6.58
400 Watt HPS Lamps	$9.70	$10.36
1000 Watt HPS Lamps	$21.98	$23.47

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-4.2 (Closed)			
Ornamental:			
250 Watt MV Lamps		$15.84	$16.92
400 Watt MV Lamps		$18.87	$20.15
150 Watt HPS Lamps		$15.74	$16.81
250 Watt HPS Lamps		$18.65	$19.92
UNDERGROUND AREA LIGHTING, Ms-6			
Monthly Charges (per Lamp):			
175 Watt MV Lamps (Closed)		$16.01	$17.10
100 Watt HPS Lamps		$14.26	$15.23
150 Watt HPS Lamps		$16.26	$17.37
METERED CUSTOMER OWNED STREET LIGHTING, Ms-7			
Customer Charge (per Month)		$7.25	$7.25
Energy Charge (per kWh)		5.8780 ¢	6.2890 ¢
COMPANY OWNED STREET LIGHTING, Ms-3 (Closed)			
Monthly Charges (per Lamp):			
2,500 Lumen - Incand. (AN)		$7.92	$8.46
4,000 Lumen - Incand. (AN)		$9.66	$10.32
6,000 Lumen - Incand. (AN)		$11.65	$12.44
10,000 Lumen - Incand. (AN)		$15.53	$16.59
F72H0 - Fluorescent (4AN)		$15.77	$16.84
F72H0 - Fluor. (2AN+2MN)		$13.88	$14.82
MUNICIPAL WATER PUMPING, Mp-1			
Customer Charge (per Month)		$10.00	$10.00
Minimum Charge: Cust. Chg. + All hp > 5 (per hp)		$0.80	$0.80
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
Primary Voltage Energy Discount (per kWh)		2.00%	2.00%
FIRE SIREN SERVICE, Mz-3			
Minimum Charge (per Month)		$2.00	$2.00
Rate per hp of Connected Capacity		38.30 ¢	38.30 ¢
WINDSOURCE, VRE (Green Pricing Tariff)			
Energy Charge Adder		1.37 ¢	1.37 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PARALLEL GENERATION, Pg-2A			
Customer Charge (per Month):			
For Generator Rating: 21-100 kW:	Delivering < 200 amps	$6.40	$6.40
	Delivering > 200 amps	$8.60	$8.60
For Generator Rating: > 100 kW		13.80	$13.80
NSPW 's Energy payments are based on LMP prices			
and are adjusted by Delivery Voltage to reflect losses.			Rates are
			automatically
Historic Day Ahead LMP payments (per kWh):			adjusted in
On-Peak		0.03640	November for
On-Peak		0.02309	the TY 2013
HYDRO ENERGY PURCHASE, Pg-2.2 (Closed)			
Customer Charge (per Month):			
For Generator Rating: 21-100 kW:	Delivering < 200 amps	$6.40	$6.40
	Delivering > 200 amps	$8.60	$8.60
For Generator Rating: > 100 kW		13.80	$13.80
Capacity Rate (Primary) paid per kWh:			
20-Year Option:			
Service beginning in 1992		4.220 ¢	4.220 ¢
Average Energy Rate (Primary):			
For Service in 1996 & After Until Changed by PSC Order		3.000 ¢	3.200 ¢
ELECTRIC SERVICE EXTENSION ALLOWANCES			
Residential & Farm Service:			
(for Rg-1, Rg-2, Fg-1)		$452.00	$499.00
General Service -- Non-Demand:			
(for Cg-1, Cg-2, Mp-1, Mz-3)		$490.00	$532.00
General Service -- Demand:			
(for Cg-5 and Cp-2) per kW:		$67.00	$79.00
Large General Service -- Demand:			
(for Cg-9 and Cp-1)			
Secondary (per kW):		$59.00	$53.00
Primary (per kW):		$50.00	$45.00
Street and Area Lighting:			
(for Ms-2, Ms-4, Ms-6)		$82.00	$108.00

Northern States Power Company

Gas Revenue Summary

Service Rate Classes	Volumes	Current Margin & Admin Revenues	+ Cost of Gas Revenues	= Rebundled Service Class Revenues	+ Proposed Distribution Rev Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled w/COG	Percent Change Rebundled w/o COG
Residential								
Residential (Rg-1)	61,622,593	$ 26,154,965	$ 29,265,354	$ 55,420,319	$ 1,731,595	$ 57,151,914	3.12%	6.62%
Subtotal	61,622,593	$ 26,154,965	$ 29,265,354	$ 55,420,319	$ 1,731,595	$ 57,151,914	3.12%	6.62%
Commercial & Industrial, Cg-1 (0 to 29,999)								
Commercial - Firm (Cg1-SSS-F)	50,407,832	$ 11,264,064	$ 23,576,958	$ 34,841,022	$ 650,261	$ 35,491,283	1.87%	5.77%
Commercial - Contract (Cg1-SSS-CD)	3,558,475	$ 621,533	$ 1,980,765	$ 2,602,298	$ 45,904	$ 2,648,202	1.76%	7.39%
Commercial - Interdepart. (Cg1-SSS-F)	153,802	$ 29,177	$ 73,442	$ 102,619	$ 1,984	$ 104,603	1.93%	6.80%
Commercial - Transport (Cg-1-CSS)	522,920	$ 75,935		$ 75,935	$ 6,746	$ 82,680	8.88%	8.88%
Subtotal Cg-1	54,643,029	$ 11,990,708	$ 25,631,166	$ 37,621,873	$ 704,895	$ 38,326,768	1.87%	5.88%
Commercial & Industrial, Cg-2 (30,000 to 199,999)								
Commercial - Interruptible (Cg-2-SSS-CD)	11,805,217	$ 237,904		$ 237,904	$ 22,430	$ 260,334	9.43%	9.43%
Commercial - Interruptible (Cg-2-SSS-I)	9,216,682	$ 1,381,434	$ 3,515,780	$ 4,897,214	$ 71,890	$ 4,969,104	1.47%	5.20%
Commercial - Transport (Cg-2-CSS)	571,315	$ 58,017		$ 58,017	$ 4,456	$ 62,474	7.68%	7.68%
Subtotal Cg-2	21,593,214	$ 1,677,355	$ 3,515,780	$ 5,193,135	$ 98,776	$ 5,291,912	1.90%	5.89%
Commercial & Industrial, Cg-3 (200,000 to 499,999)								
Commercial - Interruptible (Cg-3-SSS-I)	2,784,555	$ 271,389	$ 1,051,448	$ 1,322,837	$ 10,303	$ 1,333,140	0.78%	3.80%
Commercial - Transport (Cg-3-CSS)	1,918,203	$ 122,917		$ 122,917	$ 7,097	$ 130,014	5.77%	5.77%
Subtotal Cg-3	4,702,758	$ 394,306	$ 1,051,448	$ 1,445,754	$ 17,400	$ 1,463,154	1.20%	4.41%
Commercial & Industrial, Cg-4 (500,000 to 1,999,999)								
Commercial - Interruptible (Cg-4-SSS-I)	10,398,729	$ 761,555	$ 3,926,560	$ 4,688,115	$ 38,475	$ 4,726,590	0.82%	5.05%
Commercial - Transport (Cg-4-CSS-I)	6,050,718	$ 283,947		$ 283,947	$ 22,388	$ 306,335	7.88%	7.88%
Commercial - Contract (Contract)	1,415,600	$ 14,016		$ 14,016	$ 5,662	$ 19,678	40.40%	40.40%
Subtotal Cg-4	17,865,047	$ 1,059,518	$ 3,926,560	$ 4,986,078	$ 66,525	$ 5,052,603	1.33%	6.28%
Commercial & Industrial, Cg-5 (2,000,000 to 5,999,999)								
Commercial - Interruptible (Cg-5-SSS-I)	3,823,508	$ 238,341	$ 1,443,757	$ 1,682,098	$ 15,294	$ 1,697,392	0.91%	6.42%
Commercial - Inter-InterD (Cg-5-CSS-I)	1,051,300	$ 90,576	$ 406,669	$ 497,245	$ 4,205	$ 501,450	0.85%	4.64%
Commercial - Transport (Cg-5-CSS-I)	13,554,927	$ 534,426		$ 534,426	$ 54,220	$ 588,645	10.15%	10.15%
Subtotal Cg-5	18,429,735	$ 863,342	$ 1,850,426	$ 2,713,768	$ 73,719	$ 2,787,487	2.72%	8.54%
Commercial & Industrial, Cg-6 (6,000,000+)								
Commercial - Transport (Cg-6-CSS-I)	6,387,405	$ 202,560		$ 202,560	$ 25,550	$ 228,110	12.61%	12.61%
Subtotal Cg-6	6,387,405	$ 202,560	$ -	$ 202,560	$ 25,550	$ 228,110	12.61%	12.61%
Total Gas Sales Revenues		**$ 42,342,754**	**$ 65,240,733**	**$ 107,583,487**	**$ 2,718,460**	**$ 110,301,948**	**2.53%**	**6.42%**
Plus:								
Other Gas Revenue				$ 452,907		$ 452,907	0.00%	0.00%
Total Gas Operating Revenue				**$ 108,036,394**		**$ 110,754,855**	**2.52%**	**6.35%**

Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Monthly Customer Charge - (Rg-1)	$ 10.25	$ 10.25
Volumetric Charges:		
Distribution Service Charge - (Rg-1)	$ 0.2077	$ 0.2358
Peak Day Backup Charge (SSS-F)	$ 0.0020	$ 0.0020
Gas Acquisition Charge (SSS-F)	$ 0.0336	$ 0.0336
Commercial (Cg-1, Annual Usage < 30,000 therms)		
Monthly Customer Charge	$ 20.00	$ 20.00
Additional Meter Charge	$ 4.00	$ 4.00
Volumetric Charges:		
Distribution Service Charge	$ 0.1420	$ 0.1549
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-CD)	$ 0.0321	$ 0.0321
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)		
Monthly Customer Charge	$ 100.00	$ 100.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge - (Cg-2-SSS-CD)	$ 0.0984	$ 0.1062
Distribution Service Charge - (Cg-2-SSS-I)	$ 0.0984	$ 0.1062
Peak Day Backup Charge (SSS-F)	$ 0.0047	$ 0.0047
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256

Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)		
Monthly Customer Charge	$ 300.00	$ 300.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0653	$ 0.0690
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)		
Monthly Customer Charge	$ 350.00	$ 350.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0549	$ 0.0586
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therms)		
Monthly Customer Charge	$ 550.00	$ 550.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0480	$ 0.0520
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256

Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (Cg-6, Annual Usage 6,000,000+ therms)		
Monthly Customer Charge	$ 625.00	$ 625.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0443	$ 0.0483
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Base Average Cost of Gas Rates:		
Commodity ("Comm") rate	$ 0.5904	$ 0.3686
Peak Day Demand ("D1") rate	$ 0.0975	$ 0.1144
Annual Demand ("D2") rate	$ 0.0100	$ 0.0090
Balancing ("Bal") rate	$ 0.0039	$ -
Act 141 Volumetric Distribution Rates 1/		
Residential	$ 0.0113	$ 0.0113
Commercial (Cg-1, Annual Usage < 30,000 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therm	$ 0.0152	$ 0.0152
Commercial (Cg-6, Annual Usage 6,000,000+ therms)	$ 0.0152	$ 0.0152

1/ Act 141 volumetric distribution rates are included in the above volumetric Distribution Service Charges.

Northern States Power Company

Monthly Residential Bill Comparison

Gas Costs	Summer	Winter
Firm Sales Service	0.3776	0.4920

Monthly Use Therms		Current Customer Charge	Current Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Customer Charges	Authorized Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
Rg-1: Residential Firm Sales Service During Summer Months													
5		$ 10.25	$ 1.22	$ 11.47	$ 1.89	$ 13.35	$ 10.25	$ 1.36	$ 11.61	$ 1.89	$ 13.50	$ 0.14	1.05%
10		$ 10.25	$ 2.43	$ 12.68	$ 3.78	$ 16.46	$ 10.25	$ 2.71	$ 12.96	$ 3.78	$ 16.74	$ 0.28	1.71%
18	avg.	$ 10.25	$ 4.38	$ 14.63	$ 6.80	$ 21.43	$ 10.25	$ 4.89	$ 15.14	$ 6.80	$ 21.93	$ 0.51	2.36%
25		$ 10.25	$ 6.08	$ 16.33	$ 9.44	$ 25.77	$ 10.25	$ 6.79	$ 17.04	$ 9.44	$ 26.48	$ 0.70	2.73%
50		$ 10.25	$ 12.17	$ 22.42	$ 18.88	$ 41.30	$ 10.25	$ 13.57	$ 23.82	$ 18.88	$ 42.70	$ 1.41	3.40%
75		$ 10.25	$ 18.25	$ 28.50	$ 28.32	$ 56.82	$ 10.25	$ 20.36	$ 30.61	$ 28.32	$ 58.93	$ 2.11	3.71%
95		$ 10.25	$ 23.11	$ 33.36	$ 35.87	$ 69.24	$ 10.25	$ 25.78	$ 36.03	$ 35.87	$ 71.91	$ 2.67	3.86%
125		$ 10.25	$ 30.41	$ 40.66	$ 47.20	$ 87.86	$ 10.25	$ 33.93	$ 44.18	$ 47.20	$ 91.38	$ 3.51	4.00%
150		$ 10.25	$ 36.50	$ 46.75	$ 56.64	$ 103.39	$ 10.25	$ 40.71	$ 50.96	$ 56.64	$ 107.60	$ 4.22	4.08%
200		$ 10.25	$ 48.66	$ 58.91	$ 75.52	$ 134.43	$ 10.25	$ 54.28	$ 64.53	$ 75.52	$ 140.05	$ 5.62	4.18%
300		$ 10.25	$ 72.99	$ 83.24	$ 113.28	$ 196.52	$ 10.25	$ 81.42	$ 91.67	$ 113.28	$ 204.95	$ 8.43	4.29%
Rg-1: Residential Firm Sales Service During Winter Months													
5		$ 10.25	$ 1.22	$ 11.47	$ 2.46	$ 13.93	$ 10.25	$ 1.36	$ 11.61	$ 2.46	$ 14.07	$ 0.14	1.01%
10		$ 10.25	$ 2.43	$ 12.68	$ 4.92	$ 17.60	$ 10.25	$ 2.71	$ 12.96	$ 4.92	$ 17.88	$ 0.28	1.60%
18		$ 10.25	$ 4.38	$ 14.63	$ 8.86	$ 23.49	$ 10.25	$ 4.89	$ 15.14	$ 8.86	$ 23.99	$ 0.51	2.15%
25		$ 10.25	$ 6.08	$ 16.33	$ 12.30	$ 28.63	$ 10.25	$ 6.79	$ 17.04	$ 12.30	$ 29.34	$ 0.70	2.45%
50		$ 10.25	$ 12.17	$ 22.42	$ 24.60	$ 47.02	$ 10.25	$ 13.57	$ 23.82	$ 24.60	$ 48.42	$ 1.41	2.99%
75		$ 10.25	$ 18.25	$ 28.50	$ 36.90	$ 65.40	$ 10.25	$ 20.36	$ 30.61	$ 36.90	$ 67.51	$ 2.11	3.22%
95		$ 10.25	$ 23.11	$ 33.36	$ 46.74	$ 80.10	$ 10.25	$ 25.78	$ 36.03	$ 46.74	$ 82.77	$ 2.67	3.33%
125	avg.	$ 10.25	$ 30.41	$ 40.66	$ 61.50	$ 102.16	$ 10.25	$ 33.93	$ 44.18	$ 61.50	$ 105.68	$ 3.51	3.44%
150		$ 10.25	$ 36.50	$ 46.75	$ 73.80	$ 120.55	$ 10.25	$ 40.71	$ 50.96	$ 73.80	$ 124.76	$ 4.22	3.50%
200		$ 10.25	$ 48.66	$ 58.91	$ 98.40	$ 157.31	$ 10.25	$ 54.28	$ 64.53	$ 98.40	$ 162.93	$ 5.62	3.57%
300		$ 10.25	$ 72.99	$ 83.24	$ 147.60	$ 230.84	$ 10.25	$ 81.42	$ 91.67	$ 147.60	$ 239.27	$ 8.43	3.65%
Avg. Annual Residential Billing													
678		$ 123.00	$ 164.96	$ 287.96	$ 321.22	$ 609.18	$ 123.00	$ 184.01	$ 307.01	$ 321.22	$ 628.23	$ 19.05	3.13%

DL: 00633617

Northern States Power Company-Wisconsin
Docket 4220-UR-118
Monitored Fuel Costs for 2013

	Total Fuel Rules Cost	System Requirements	Monthly $/kWh	Cumulative $/kWh
January	$ 99,502,442	3,908,277,000	$ 0.02546	$ 0.02546
February	86,010,289	3,464,646,000	$ 0.02483	$ 0.02516
March	91,692,462	3,605,956,000	$ 0.02543	$ 0.02525
April	87,900,287	3,294,527,000	$ 0.02668	$ 0.02558
May	92,710,473	3,471,330,000	$ 0.02671	$ 0.02580
June	94,736,702	3,849,584,000	$ 0.02461	$ 0.02559
July	108,281,873	4,280,612,000	$ 0.02530	$ 0.02554
August	106,092,692	4,128,944,000	$ 0.02569	$ 0.02556
September	90,802,480	3,555,480,000	$ 0.02554	$ 0.02556
October	88,557,671	3,455,883,000	$ 0.02563	$ 0.02556
November	90,075,118	3,419,131,000	$ 0.02634	$ 0.02563
December	94,217,160	3,810,581,000	$ 0.02473	$ 0.02555
Total	$ 1,130,579,649	44,244,951,000	$ 0.02555	

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates | 4220-UR-118

**DISSENT AND CONCURRENCE
OF COMMISSIONER ERIC CALLISTO**

While I generally concur in the Final Decision, I write separately to explain my dissenting position on two issues.

I also write separately here in concurrence, as I did in the recent rate decisions for Superior Water, Light and Power Company, Madison Gas and Electric Company, and We Energies, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.[1]

Revenue Allocation

The electric rate increase in this case is substantial—just a bit over 6 percent.[2] The allocations proposed by both Northern States Power Company-Wisconsin (NSPW) and Commission staff recognized the magnitude of this increase and were similar, though Commission staff had a wider range from the average. Commission staff had a range of 0.45 percent above the average to 0.95 percent below the average, while NSPW had a range of

[1] *See Final Decisions* in dockets 5820-UR-113 (Commissioner Callisto, concurring), 3270-UR-118 (Commissioner Callisto, concurring and dissenting in part), and 5-UR-106 (Commissioner Callisto, concurring and dissenting in part).

[2] For those electric customers who also take gas from NSPW, they will also experience an increase in their gas rates, approximately 2.53 percent.

0.30 percent above the average to 0.20 percent below the average.[3] The Wisconsin Industrial Energy Group and the Citizens Utility Board argued for lesser increases to their constituencies.

I proposed an increase that was based upon an approximate 0.25 percent spread from the average, with the residential class receiving the highest increase (6.30 percent) and large commercial and industrial (C&I) class receiving the smallest (5.8 percent). In acknowledgement of the collaborative process the Commission has on these issues, I indicated receptivity to a wider range, and explicitly agreed to Commissioner Nowak's alternate proposal, which had the residential class at 6.4 percent and the large C&I class at the same increase I proposed, 5.8 percent.

By the time the majority reached consensus, it agreed to a 7.2 percent increase for the residential class and only a 5.0 percent increase for the large C&I class.[4] In an effort to reach a 3-0 vote on this important issue, and to mitigate this large increase over the average to the residential class, I indicated my willingness to cap the residential class at 7.0 percent. This was not acceptable to my colleagues.

Thus the swing from Commissioner Nowak's original proposal, a proposal to which I agreed, is approximately $1.8 million more to the residential and small C&I classes, all largely to the benefit of the large C&I classes. This is contrary to the reasonable allocations proposed by Commission staff and NSPW, and is too skewed to the benefit of a small number and type of customers.

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[3] NSPW's allocation assumed an overall increase of 6.7 percent, its filed request, while Commission staff's allocation assumed an increase of 5.65 percent, the result of their audit. The ultimate increase, after late adjustments, is 6.09 percent.

[4] Commission staff has rerun its models in an effort to reach the majority's desired conclusion. The final allocations lead to a 7.07 percent increase to residential customers, and an unanticipated (at least as reflected by our discussion of record) 7.23 percent increase for small C&I customers. Large C&I is at 5.0 percent. *See* Appendix B.

Discounts for C&I Customers

The majority agreed to both the high load factor energy charge credit and voltage discount changes proposed by NSPW. I believe the high load factor change that the Commission agreed to in this case, which provides approximately $679,000 of benefit to high load factor customers, is appropriate and appropriately incremental. While a reasonable argument is made to change the transmission voltage discounts, it benefits only eight customers, many of whom are also benefitting from the high load factor change. These two changes, together, amount to more than $900,000, and collectively go too far.

2005 Wisconsin Act 141 Large Energy Customer Contributions

Energy efficiency programs in Wisconsin are governed by 2005 Wisconsin Act 141 (Act 141). Among other things, Act 141 requires the state's utilities to collectively establish and fund a statewide energy efficiency program (Focus on Energy), establishes priorities for the expenditure of those funds, and creates a system of joint oversight, involving the state's utilities, the Commission, and the third party contractor that administers the program. *See generally* Wis. Stat. § 196.374.

Focus on Energy is funded through ratepayer dollars, at an amount equal to 1.2 percent of utility revenues. Wis. Stat. §§ 196.374(3)(b)2. and (5)a. However, each individual ratepayer's contribution to Focus on Energy is not equal to 1.2 percent of their utility bills. While the Commission has determined that the rate classes should generally pay an amount equal to the amount of Focus on Energy incentives distributed to their class, a limited number of large customers pay much less. That disparity and the subsidy that it necessitates is the result of a section of Act 141 which specifically directs that certain "Large Energy

Customers"[5] (LECs) pay into Focus on Energy the amount they paid towards similar programs in 2005, rather than the amount determined by the Commission. Wis. Stat. § 196.374(5)(b)1. and 2005 Wisconsin Act 141, § 102(8)(c). There are currently 869 LECs in Wisconsin, and specifically 50 LECs in the service territory of NSPW.

Most LECs pay less into Focus on Energy than they otherwise would in the absence of the statutory exemption. Some LECs pay no money into Focus on Energy because they were paying no money to similar programs in 2005. Regardless of how much they pay into the program, all LECs remain eligible to receive the benefits of Focus on Energy, at an undiminished level.

In the NSPW rate case we approve today, LECs are paying about $1.4 million less than they would if all customers were required to pay proportionally equal amounts.[6] The amount last year was about the same.[7] Accounting for the state's six largest utilities, in 2010, the most recent year for which full data is available, LECs paid $16.2 million less than they would have if the statutory exemption didn't exist.[8] Because the utilities are required to fund the program at 1.2 percent of revenues, that missing LEC money must come from somewhere else, and indeed it does. Those costs are allocated to other non-residential customers. In this case, all of NSPW's commercial, industrial, and lighting customers that do not meet the LEC threshold are

[5] A "large energy customer" is a customer that has a demand of at least 1,000 kilowatts of electricity per month or of at least 10,000 decatherms of natural gas per month and, in a month, is billed at least $60,000 for electric service, natural gas service, or both. Wis. Stat. § 196.374(1)(em).

[6] This includes both gas and electric large energy customers of the utility.

[7] On average, the NSPW LECs enjoy a 63 percent discount on the electric rate they pay for Act 141 programs when compared against proportionally equal amounts. The rate for all of the non-residential customers to pay for Act 141 programs would have been approximately $0.00091/kilowatt-hour (kWh), if not for this legislation. Under the approved rates for 2013, LECs will pay $0.00034/kWh for Act 141 program contributions, while non-LECs will pay $0.00128/kWh. Under present rates, the disparity is $0.00040/kWh vs. $0.00121/kWh.

[8] *See* Wisconsin Legislative Audit Bureau Report 11-13, Evaluation of the Focus on Energy Program, pp. 21–22 (December 2011).

required to pick up these extra amounts, and essentially subsidize the rate break enjoyed by 50 LECs.

And while, generally, under-collection from LECs is the result of the Act 141 exemption, some LECs in Wisconsin have actually paid more than their proportional share of utility revenues because of the operation of the exemption.[9] Either way, the result is inequitable.

Furthermore, the LEC exemption creates perverse incentives that may not be readily apparent. If a LEC is close to the cutoff line for retaining this designation (*i.e.*, its monthly energy use and/or bill amounts are dropping close to the statutory thresholds), it may not choose to pursue energy efficiency because the energy savings may have a value less than the likely "full" Focus on Energy payment it would be required to make as a non-LEC. Conversely, those customers falling just short of the LEC threshold may have an incentive to use more energy—even when they don't need it—if they believe getting the LEC designation (and the resulting lower Focus on Energy payment) will be more valuable than the energy costs incurred to get to the threshold. It cannot be that Act 141 was intended to create economic incentives for inefficient and wasteful energy usage, which is precisely what the LEC exemption promotes.

Freezing the LEC contributions to Focus on Energy at 2005 levels was meant to be temporary.[10] Act 141 required the Commission, by no later than the end of 2008, to provide the Legislature with a recommendation for equitable cost recovery from all rate classes. Wis. Stat. § 196.374(5)(bm)1. While the Commission did submit a proposal recommending a 3-year

[9] *See id.* at p. 22, Table 7 (illustrating how Wisconsin Power & Light Company's LECs pay $616,000 more that they would without Act 141's exemption).
[10] *See id.* at p. 20 ("Legislative documents describe [the Act 141 LEC exemption] as a 'first step' . . . .).

phase-in to proportionally equal funding for LECs, no legislative action was undertaken.[11] As a result, most LECs continue to enjoy proportionally lower contributions to Focus on Energy than other customers in their own rate classes, and in other non-residential customer classes.[12] And those rate breaks for the LECs continue to be subsidized by other commercial and industrial customers.

Not every inequity created by the statutes warrants the Commission's attention. However, where the Legislature empowered the Commission to make a recommendation to resolve an acknowledged disparity in the initial statutory scheme, where that recommendation was not acted on, and where the inequity persists, it is reasonable to make a run at it again. I encourage the Legislature to resolve this issue in the next legislative session.

[11] The Commission's 2008 recommendation can be found at PSC REF#: 106987.

[12] LEC contributions to Focus on Energy are subject to annual adjustments equal to the lesser of the percentage increase in the host utility's operating revenues in the preceding year or the increase in the consumer price index. Wis. Stat. § 196.374(5)(bm)2.