PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates — 4220-UR-119

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 2014.

Final overall rate changes are authorized consisting of a $19,537,995 annual rate increase for Wisconsin retail electric operations, a 3.11 percent increase; and no change in rates for Wisconsin retail natural gas operations, for the test year ending December 31, 2014, based on a 10.20 percent return on common equity.

Introduction

On June 1, 2013, NSPW filed for authority to increase its Wisconsin retail electric and natural gas rates on January 1, 2014. NSPW requested an overall increase in annual Wisconsin retail electric revenues of $ 40.0 million, an increase of 6.5 percent over present revenues. NSPW also requested an overall increase in annual Wisconsin retail natural gas revenues of $4.7 million, an increase of 3.5 percent. These proposed increases are based on a 10.40 percent return on common equity.

A hearing was held on October 30, 2013, in Madison, Wisconsin, to receive technical information and public comments into the record.

The Commission considered this matter at its open meeting on December 5, 2013. 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 $630,194,000 for the test year ending December 31, 2014, which results in an adjusted net operating income of $63,036,000 and an annual revenue deficiency of $19,538,000. 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 $896,151,000 at current rates for the test year is 7.03 percent, which is inadequate.

3. A reasonable increase in operating revenue for the test year to produce an 8.34 percent return on NSPW's average net investment rate base for Wisconsin retail electric operations is $19,538.000.

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 $113,942,000 for the test year ending December 31, 2014, which results in an adjusted net operating income of $7,508,000 and no annual revenue deficiency.

6. For the Wisconsin retail natural gas utility operations, the estimated rate of return on average net investment rate base of $90,020,000 at current rates for the test year is 8.34 percent, which is adequate.

7. NSPW's filed natural gas operating income statements and net investment rate bases for the test year, as adjusted for Commission decisions, are reasonable.

8. A 2014 total NSPW system test-year fuel cost of $1,250,200 is reasonable.

9. A 2014 total NSPW system test-year fuel rules monitoring level of fuel costs of $1,122,600, or $0.02530 per kilowatt-hour, as shown in Appendix C, is reasonable.

10. It is reasonable to depart from the traditional most recent five-calendar year (2008-2012) average equivalent forced outage rate (EFOR) for Sherco Unit 3 and the nuclear units as proposed by Commission staff.

11. It is reasonable to update fuel costs to reflect market prices for coal, natural gas, electricity, and heating oil as of November 13, 2013.

12. It is reasonable to continue to monitor NSPW's monitored fuel costs using an annual bandwidth of plus or minus 2 percent.

13. It is reasonable to continue using the unadjusted New York Mercantile Exchange (NYMEX) futures to forecast commodity costs not covered by contract.

14. It is reasonable to use Commission staff's estimate of test-year electric sales for the Cg-9 rate schedule in the calculation of revenue requirement.

15. It is not reasonable to include the payroll and related costs associated with the annual incentive plan costs in 2014 revenue requirement.

16. It is appropriate to limit non-union forecasted merit increases to inflation (1.7 percent) in the development of test-year payroll expense and related taxes.

17. It is reasonable to incorporate Commission staff's adjustment to Federal Energy Regulatory Commission (FERC) account 931, Rents, in the projection of the 2014 test-year level of expense.

18. It is reasonable to establish the amortization of manufactured gas plant (MGP) cleanup costs in the 2014 test-year revenue requirement at $4,718,704. This level eliminates the $1,057,756 excess natural gas revenue amount and results in no change in natural gas rates.

19. It is appropriate to defer the impact of the Minnesota Public Service Commission (MPUC) decision regarding the Monticello Nuclear Plant Extended Power Uprate (EPU) and Life Cycle Management (LCM) pending the receipt of the uprate license and a final decision by the MPUC on whether the cost overruns were prudent.

20. It is appropriate to require NSPW to provide quarterly reports to the Commission detailing the status of MPUC's review of the Monticello Nuclear Plant licensing and non-licensing cost overruns.

21. It is appropriate to include the updated U.S. Department of Energy (DOE) settlement payment in the final determination of the 2014 test-year revenue requirement.

22. It is appropriate to deny NSPW's request to create a farm rewiring escrow.

23. It is reasonable to include all uncontested Commission staff adjustments to NSPW's filed electric and natural gas revenue requirements.

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

25. An appropriate target level for the test-year average common equity measured on a financial basis is 52.50 percent.

26. A reasonable estimate of the debt-equivalent of NSPW's off-balance sheet obligations associated with operating leases is $8,198,809.

27. A reasonable financial capital structure for the test year consists of 52.51 percent equity, 44.28 percent long-term debt, 2.55 percent short-term debt, and 0.66 percent debt equivalence for off-balance sheet obligations.

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

29. 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.

30. A reasonable regulatory capital structure for the test year consists of 52.54 percent equity, 44.92 percent long-term debt, and 2.54 percent short-term debt.

31. It is reasonable to implement dividend restrictions for NSPW based on the capital structure determinations in this proceeding.

32. A reasonable interest rate for short-term borrowing through commercial paper is 0.40 percent.

33. A reasonable estimate of the cost of the new long-term debt issue for the test year is 5.20 percent.

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

35. A reasonable return on equity is 10.20 percent.

36. A reasonable weighted average composite cost of capital is 7.93 percent.

37. The reasonable level of expensed conservation costs recoverable in rates for the 2014 test year is $9,277,723 for electric operations and $1,729.173 for natural gas operations. The level for electric operations consists of the conservation budget of $9,167,607 plus an

escrow adjustment of $110,116 to reflect the estimated overspent balance as of January 1, 2013, of $220,231 amortized over two years. The level for natural gas operations consists of the conservation budget of $1,856,262 plus an escrow adjustment of ($127,089) to reflect the estimated underspent balance as of January 1, 2013, of ($254,178) amortized over two years.

38. It is appropriate for NSPW to work with Commission staff to develop metrics for the customer service conservation (CSC) activities and services approved for inclusion in the conservation escrow. Commission staff should bring this issue back to the Commission if appropriate metrics are not agreed upon by January 31, 2014.

39. It is reasonable to rely upon more than one cost-of-service study (COSS) and other factors when allocating revenue responsibility.

40. It is reasonable to approve the rate changes for electric service as shown in Appendix B.

41. It is reasonable to increase the voltage discount for eligible large time-of-use (TOU) customers to 9 percent.

42. The Distribution Extension Allowances prepared by Commission staff, as adjusted for Commission decisions, are reasonable.

43. It is reasonable to allow customers who initiated service under the Pg-1 tariff prior to January 1, 2011, with less than 20 kilowatt (kW) name plate capacity to continue to be paid for their net monthly excess generation at their full retail rates through December 31, 2014. It is reasonable to then transition these customers to the terms of the Pg-1 tariff in effect at the time.

44. NSPW's proposed Pg-1 Net Energy Billing Tariff changes related to the treatment of on-peak and off-peak energy are reasonable.

45. It is reasonable to utilize the results of all of the natural gas COSS as guides for revenue allocation and rate design.

46. It is reasonable to make no change in natural distribution service or gas supply service rates.

47. It is reasonable to approve the natural gas tariff changes, which include eliminating the Natural Gas Vehicle (NGV) gas supply tariff, eliminating the flex-up provision of the SSI-I Interruptible tariff, adding clarifying language to the extension rules and removing obsolete language regarding deferred payment agreements and transition costs.

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 Appendix B, and the fuel cost treatment set forth in Appendix C, 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 more than 200 communities in northwestern Wisconsin and the western tip of the Upper Peninsula of Michigan. In addition, NSPW provides natural gas service to approximately 108,000 customers in Wisconsin and Michigan. NSPW is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel Energy).

Income Statement

NSPW, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of NSPW's 2014 electric and natural gas utility operations. Significant issues pertaining to the income statement are addressed separately below.

Electric Fuel Costs

A reasonable test-year level of monitored fuel is $1,122.6 million, which reflects the cost of fuel as defined by the test-year estimate of native energy requirements of 44,378,592 megawatt-hours (MWh), and results in an average net monitored fuel cost per MWh of $25.30. Appendix C shows the monthly fuel costs to be used for monitoring purposes. The total fuel costs are based on indices for coal, electric, natural gas, and heating oil prices for November 13, 2013. It is reasonable to monitor NSPW system's fuel cost using a plus or minus 2 percent bandwidth, as provided for in Wis. Admin. Code § PSC 116.06(3).

Equivalent Forced Outage Rates

Commission staff proposed two adjustments to NSPW's EFORs—one to Sherco Unit 3 and the other to the nuclear units. Generally speaking, the Commission bases forecasted EFORs on the most recent five-calendar year average, in this case 2008-2012. However, the Commission has departed from that general rule in certain cases.

Sherco 3 had a catastrophic outage that occurred in late 2011 and lasted through most of 2013. Forced outages that last for over one year are not representative of the kinds of forced outages that are forecasted. As such, NSPW's 2014 Fuel Cost Plan used a five-year calendar average (2007-2011) of EFORs for Sherco 3 in order to eliminate the effect of the extended outage. Commission staff agreed that Sherco 3's forecasted EFOR should not reflect Sherco 3's 2012 EFOR, but also proposed to adjust Sherco 3's 2011 EFOR to remove the effect of the catastrophic outage. The Commission finds it reasonable to reflect Commission staff's proposed adjustment to the EFOR for Sherco 3.

For the nuclear units (Monticello and Prairie Island 1 and 2), NSPW filed fuel costs based on the 2008-2012 average EFORs. Commission staff proposed to use the average EFORs for 2007-2011 since, in 2012, two of the units had a very poor EFOR, while the other had an excellent EFOR. The Commission finds it reasonable to reflect Commission staff's proposed adjustment to the EFORs for the NSPW system's nuclear units.

Spot Coal, Natural Gas, Oil, and Electricity Prices

The Commission has historically used unadjusted NYMEX futures prices to forecast fuel commodity costs that are not established by contract for a future test year. These futures prices have been considered a proxy for the actual prices that will be paid in the future for these commodities.

Commission staff proposed to adjust fuel costs based on adjusting fuel commodity prices by an average historical ratio of settlement to futures prices. Data for the last six years shows that, on average, settlement prices were 15.5 percent lower than the mid-November futures price for that time period. In some years, this has been a contributing cause to fuel cost over-collections for NSPW. While much of these over-collections must be refunded to ratepayers, NSPW keeps any over-collections within the 2 percent fuel tolerance band, just as it must absorb any fuel cost under-collections within this band.

Commission staff's proposed adjustment is premised upon an assumption that there are risk premiums built into NYMEX futures prices and that the relationship of futures prices to settlement prices over a recent set of years proves the existence of a risk premium. The Commission is not satisfied that there is enough evidence in the record to support the premise that the NYMEX futures market reflects a built-in risk premium, which ensures that the futures price will be reliably higher than the settlement price. The Commission is not persuaded that the studies relied upon by Commission staff support the proposition that risk premiums exist in the individual commodity futures at issue in this proceeding. Further, even if such a premium exists, the Commission is not confident that the methodology proposed by Commission staff accurately isolates and accounts for any such premium.

While the Commission applauds Commission staff for attempting to fashion an adjustment that takes into account more recent changes in the natural gas market that have resulted in lower natural gas prices, the Commission believes that the use of NYMEX futures prices (that reflect prices that prevail in the markets used by sophisticated parties on all sides of the transaction) remain the most reliable predicator of future spot prices. Commission staff may continue to monitor the relationship between NYMEX future prices to settlement prices, but the Commission is not prepared at this time to further evaluate adjustments, modifications, or different methodologies that could be used to forecast commodity costs.

The Commission therefore determines that NYMEX futures prices, unadjusted for the recent relationship of futures prices to settlement prices, should be used to forecast fuel commodity costs not covered by contract. The Commission determines that the estimated spot coal, natural gas, electricity, and heating oil prices based on 2014 NYMEX futures prices and the Midcontinent Independent System Operator, Inc., Indiana Hub futures prices from November 13, 2013, per NSPW’s fuel cost update delayed exhibit, are reasonable.

2014 Fuel Cost Plan

NSPW requested that the Commission-authorized monitored fuel costs for 2014 be designated as the NSPW 2014 Fuel Cost Plan for purposes of Wis. Admin. Code § PSC 116.06(3). Wisconsin Admin. Code § PSC 116.06(3) establishes a 2.0 percent fuel cost tolerance band “unless the Commission sets a different percentage when approving a fuel cost plan . . . .” Within this band, the utility must absorb any increases in fuel cost and is not required to refund any decreases in fuel cost. The Commission finds it reasonable to allow NSPW to use the 2.0 percent Commission-authorized monitored fuel costs for NSPW’s 2014 Fuel Cost Plan.

Cg-9 Sales

Commission staff reviewed NSPW’s filed electric sales forecast by rate schedule and compared it to historical sales for each rate schedule. Commission staff noted that the Cg-9 rate schedule had shown strong growth for the most recent three years and asked NSPW to explain why sales in that rate schedule had grown so significantly and why NSPW did not expect that growth to continue. Commission staff received a response that did not provide adequate information. NSPW responded to Commission staff’s draft sales forecast by providing significant information about the Cg-9 rate schedule as well as other rate schedules. Commission staff was able to adjust its sales forecast to incorporate much of this new information, which was provided just prior to staff’s deadline for this area, but lacked sufficient time to ask questions about this information. NSPW disagreed with Commission staff’s revised forecast for the Cg-9 rate schedule, saying that 2013 sales for that rate schedule, combined with the Cp-1 rate schedule, were not growing beyond the 2012 level.

The Commission finds that Commission staff’s forecast for the Cg-9 rate schedule, reflecting a continued growth pattern, adjusted for customer additions and losses, is reasonable.

The Commission finds the information provided by NSPW to be inadequate, in part because NSPW combined sales information for two rate schedules to support its forecast for the Cg-9 rate schedule.

Annual Incentive Plan Compensation

The non-bargaining employee cash compensation includes two components: base salary and the Annual Incentive Plan (AIP). Eligible employees have a targeted annual incentive expressed as a percentage of base salary. In order for any AIP payments to occur, all individual, business area and corporate goals must be met, the affordability trigger satisfied, and finally, the chief executive officer's (CEO) determination on whether to pay out the incentive compensation. Commission staff reduced NSPW's 2014 payroll and associated expenses by $2,743,533 to eliminate the costs associated with the AIP.

NSPW maintained that the Commission should allow recovery of all AIP costs because it allows the total cash compensation to be competitive with the relevant market, it is a cost savings approach to providing cash compensation, and it is consistent with the standards and best practices of public and private companies in the United States. NSPW stated that they had made significant changes to the AIP. Additionally, NSPW included a refund proposal and offered a compromise position. NSPW stated that the ties to the financial aspects have been removed--removing the earnings per share target as a goal and restricting the plan's key performance indicators such that less than 3 percent of the total plan payout is tied to a financial measure. NSPW offered to refund to customers any amount of incentive pay collected in rates, but not paid to employees, which NSPW believes effectively neutralizes the CEO discretion provision and ensures no shareholder windfall. NSPW proposed a compromise position on AIP by removing the portion of AIP related to financial measures and the portion paid to mid- and upper-level management.

Commission staff testified that NSPW's changes to the AIP were not significant, that merely moving the earnings per share target from a goal to an affordability trigger does not lessen its impact. In effect, not meeting the affordability trigger has the same impact as not meeting the goal—nonpayment of the incentives. While the AIP still retains the CEO discretionary component, NSPW's offer to refund to customers any amount of incentive collected in rates, but not paid to employees, could be viewed as somewhat neutralizing that discretion. However, past payouts indicate that any refund is unlikely. Commission staff noted that there are problems with the structuring of goals and the complexity of the plan.

NSPW argued that the Commission has been unclear in its prior decisions of its position on incentive compensation. The Commission has provided direction in its prior decisions including the following reasons for disallowance:

- Economic conditions—customer ability to pay
- Validity of third party survey data
- Goals tied too closely to financial measures
- Goals should benefit both shareholder and customer
- Too much CEO discretion over payout amount

While the Commission believes progress has been made in the incentive design, there are still excessive ties to financial performance and lack of clearly-defined ratepayer benefits and/or savings. NSPW's continued funding of AIP despite Commission disallowance indicates that NSPW sees value to shareholders.

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, it is appropriate for the Commission to exclude these costs in this docket.

Annual Merit Pay Factors

NSPW's filed payroll forecast for the test year included union wage increases for 2013 of 3.25 percent and 2014 of 3.00 percent under signed contracts. NSPW's test-year payroll forecast also included merit increases for non-union employees of 2.5 percent for 2012, 2.75 percent for 2013, and 3.00 percent for 2014. Commission staff's test-year payroll forecast accepted the union increases for 2013 and 2014 and the non-union merit increases for 2012 and 2013, but replaced the 2014 non-union merit increase of 3.00 percent with the inflation rate of 1.7 percent.

NSPW maintained that it balances factors such as reviewing external market surveys regarding base salary increases, comparing potential increases in base salary to bargaining employees, economic conditions, and company performance to arrive at an equitable increase in base salaries. For bargaining unit employees, the annual increases are typically associated with amounts negotiated in labor contracts. Commission staff's forecasted merit increases for non-union employees reflect current economic conditions and impacts on businesses and small-use customers from recent increases in their utility bills, while still providing utility employees reasonable wage adjustments.

The Commission finds it is appropriate to incorporate 1.7 percent payroll merit increases in 2014 for non-union employees in the development of the test-year payroll expense. The Commission directed staff to examine the use of inflation in the next rate case.

Rents

Commission staff reviewed FERC account 931 Rents, by looking at past history and determined that a three-year average was the best estimate of the 2014 test-year level of expense for this account. After the audit was closed, NSPW argued that rents are accounted for in a series of FERC accounts, and, to determine if rent expense is reasonable, all FERC accounts that include rent expense need to be reviewed. Commission staff reviewed the rent accounts in the various FERC accounts and functional areas. The rents associated with electric power production, transmission, and gas distribution were reviewed individually and within those functional areas, and found to be reasonable. The rents in those accounts are for different assets than those in FERC account 931, Rents, for example, a crane versus a software package. Combining the different rent accounts mixes assets and can lead to misleading trend results.

NSPW raised the concept of offsetting FERC account 931 with FERC account 922, Administrative Expense Transferred. NSPW was unable to provide a complete functional breakdown of both FERC accounts 931 and 922 for past years or the test year. There is no indication that there is a direct offset between the two accounts.

It is appropriate to accept Commission staff's adjustment to FERC account 931 rents.

Monticello Nuclear Plant

MPUC made an adjustment related to the Monticello Nuclear Plant in Northern States Power-Minnesota's (NSPM) 2013 test-year rate case. The MPUC decision on the LCM/EPU project cost was two-fold. One, the MPUC moved 41.6 percent of the plant additions since the last rate case, which was based on a 2011 test year, and 100 percent of the licensing costs from plant-in-service to Construction Work in Progress (CWIP) pending the Nuclear Regulatory Commission (NRC) licensing the plant at the higher rate. Until that happens, the plant is operating at the lower rate, and the MPUC determined that the EPU additions are not used and useful. Additionally, the cost of the entire LCM/EPU project came in 83.3 percent higher than NSPM estimated in the Minnesota Certificate of Need application (and the basis for the MPUC's approval of the project). MPUC has opened a docket to determine whether NSPM's handling of the LCM/EPU project was prudent and whether NSPM's request for recovery of the cost overruns is reasonable. The cost overruns are approximately $345 million.

NSPW argued that MPUC's movement of the costs associated with the EPU project out of plant-in-service to CWIP, is a Minnesota retail adjustment and contended that it does not have to adjust its generally accepted accounting principles (GAAP) books for that adjustment. NSPW argued that the interchange agreement (IA) transfers are based on FERC books and those are identical to its GAAP books. Commission staff stated that this creates a disconnect between the two jurisdictions. Minnesota retail customers have a lower plant-in-service balance and a higher CWIP balance than what flows through the IA to NSPW customers. NSPW customers are paying for plant-in-service that the originating commission (MPUC) has determined is not currently used and useful and will not be until NRC approves the license uprate. The MPUC decision also ties the dollars transferred to CWIP to a determination on prudence. NSPM cannot put the plant back into plant-in-service until the NRC license is received *and* MPUC has determined the cost overruns were prudent. Commission staff recommended that the Commission mimic the MPUC decision and defer the IA bill impact at the allowance for funds used during construction (AFUDC) rate until MPUC issues it decision. NSPW argued that no adjustment was necessary, but if an adjustment were made, it should deal only with new costs in the 2014 test year to avoid the issue of retroactive ratemaking.

The Commission has the legal authority to question the prudence of costs flowing through the IA. The Commission is adjusting the projected IA bill for the impact of the MPUC decision. This adjustment and deferral do not constitute retroactive ratemaking. If imprudence is found, the imprudent costs can be disallowed on a going-forward basis. It is appropriate to mimic the MPUC decision and defer the IA bill impact of $4,108,000 at the excess AFUDC rate until such time as MPUC reaches a final determination. This approach is reasonable as it protects Wisconsin ratepayers as well as NSPW. The Commission also believes it is appropriate to monitor the MPUC proceeding and require NSPW to submit quarterly reports to the Commission detailing the MPUC's review of the overrun costs. Commission staff shall review NSPW's quarterly reports and submit a recommendation to the Commission regarding the process to be used in the next rate case to evaluate the prudence of those costs. The Commission reserves the right to hold its own proceeding on the Monticello issue.

U.S. Department of Energy Settlement Proceeds

NPSW's initial rate case filing contained an estimated fourth DOE settlement payment of $4,525,790.00 arriving late in 2013. NSPW updated the amount in rebuttal testimony to $6,265,975.16. The Commission finds it is appropriate to include the $6.3 million DOE settlement payment in the final determination of the 2014 test-year revenue requirement.

Farm Rewiring Program

NSPW requested the Farm Rewiring Program costs be included in a separate escrow account and the expenses trued-up in future rate proceedings in the same manner as conservation escrow practices.

The Commission finds that the issue was not adequately developed in the record. The Commission finds it appropriate to deny NSPW's request. Farm Rewiring Program costs shall be treated as non-escrow operation and maintenance costs.

Conservation Budget and Escrow Adjustment

Customer Service Conservation

The reasonable level of expensed conservation costs recoverable in rates for the 2014 test year is $9,277,723 for electric operations and $1,729.173 for natural gas operations. The level for electric operations consists of the conservation budget of $9,167,607 plus an escrow adjustment of $110,116 to reflect the estimated overspent balance as of January 1, 2013, of $220,231 amortized over two years. The level for natural gas operations consists of the conservation budget of $1,856,262 plus an escrow adjustment of ($127,089) to reflect the estimated underspent balance as of January 1, 2013, of ($254,178) amortized over two years. This escrow budget reflects a $55,000 adjustment for bonuses and a $190,581 adjustment for advertising and promotion expenses. NSPW accepted Commission staff's adjustment for bonuses. The advertising and promotion expenses requested by NSPW are intended to increase participation in the Focus on Energy program, either directly or through NSPW's voluntary utility energy efficiency program. The Commission finds that the level of advertising and promotion expenses requested by NSPW are not appropriate.

Metrics of Success

NSPW did not propose metrics of success for its CSC activities and services. The Commission's Order in docket 5-BU-102, dated July 13, 2012, requires utilities to work with Commission staff to develop metrics for their CSC activities and services to ensure CSC funds provide a useful service to ratepayers. The Commission finds it appropriate for NSPW to work with Commission staff to develop metrics of success for the 2014 CSC activities and services approved by the Commission. Because NSPW has not provided metrics of success for CSC activities in the past, the Commission finds it reasonable for Commission staff to bring this issue back to the Commission if metrics are not agreed upon by January 31, 2014.

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 operating income statements are appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility operating income statements at present rates for the 2014 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Retail Electric (000's)	Retail Natural Gas (000's)
Operating Revenues		
Sales	$628,217	$113,483
Other Operating Revenues	1,977	459
Total Operating Revenues	$630,194	$113,942
Operating Expenses		
Production Expense	$385,491	$ 4949
Purchased Gas Expense	---	67,446
Gas Storage Expense	---	384
Transmission Expenses	(15,687)	---
Distribution Expenses	23,777	8,517
Customer Accounts Expenses	9,265	3,291
Customer Service and Sales Expenses	12,261	2,351
Administrative and General Expenses	35,355	5255
Total Operation & Maintenance Expenses	$450,462	$92,192
Depreciation Expense	66,574	8,796
Amortization Expense	207	57
Taxes Other Than Income Taxes	23,123	1,889
State Income Taxes	2,543	(2,010)
Federal Income Taxes	(6,053)	(6,865)
Deferred Income Taxes–Net	30,974	12,398
Investment Tax Credits Restored	(634)	(24)
Total Operating Expenses	$567,196	$106,435
Chippewa Flambeau Improvement Company Income	38	---
Net Operating Income	$ 63,036	$ 7,508

Average Net Investment Rate Base

Summary of Average Net Investment Rate Bases

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to NSPW's filed average net investment rate bases are appropriate. Accordingly, the estimated Wisconsin retail electric and gas utility average net investment rate bases for the 2014 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Retail Electric (000's)	Retail Natural Gas (000's)
Utility Plant in Service	$2,077,018	$243,274
Less: Accumulated Reserve for Depreciation	932,831	136,514
Net Utility Plant	$1,144,187	$106,760
Add: Fuel Inventory	8,052	---
Natural Gas in Storage	---	5,907
LNG/Propane Fuel Inventory	---	419
Materials and Supplies	4,501	625
Investments in Associated Companies	537	---
Less: Accumulated Deferred Income Taxes	247,565	21,823
Customer Advances – net of tax	13,561	1,869
Average Net Investment Rate Base	$896,151	$90,020

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, 2014, results in a rate of return on average net investment rate base of 7.03 percent for Wisconsin retail electric utility operations and 8.34 percent for Wisconsin retail natural gas utility operations.

Inflation Rates

Reasonable inflation rates for 2013 and 2014 are 1.5 percent and 1.7 percent, respectively. The inflation rates are based on the average of current estimates from the monthly publication of *Global Insight U.S. Economic Outlook* and *Blue Chip Economic Indicators*. This is a reasonable and objective method of determining the expected rates of inflation.

Financial Capital Structure and Dividend Restriction

The long-term range for NSPW's common equity ratio, on a financial basis, found reasonable in docket 4220-UR-117 was 50 to 55 percent common equity. In this proceeding, the Commission finds that this range remains reasonable. 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. Furthermore, the Commission will continue to evaluate the appropriate capitalization in subsequent proceedings.

With the rebalancing of NSPW's capitalization, it is necessary to forecast test-year equity infusions from and special dividends to Xcel Energy to maintain a test-year average equity near a target level within the approved range. An appropriate target level for the test-year average common equity measured on a financial basis is 52.50 percent. This target level is consistent with the 50 to 55 percent range established by the Commission.

The treatment of off-balance sheet obligations associated with NSPW's operating leases was an uncontested issue. Adjustments for these off-balance sheet obligations are made by Standard and Poor's (S&P) and other financial analysts when calculating various financial ratios, including the total debt to total capital ratio. Consequently, it is reasonable that any debt equivalent associated with NSPW's off-balance sheet obligations, including operating leases, be included in determining NSPW's financial capital structure. A 100 percent factor adjustment for calculating the debt equivalents of the operating leases is used in this docket. Consequently, a reasonable estimate of the amount of off-balance sheet debt equivalents to be imputed into NSPW's financial capital structure is $8,198,809.

To independently examine off-balance sheet debt obligations, it is reasonable to require that NSPW submit 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 purchased power adjustment (PPA) 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 and other major credit rating agencies' determinations 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 are not available.

Incorporating the above off-balance sheet debt equivalents and other Commission determinations, NSPW's financial capital structure for the test year will consist of 52.51 percent equity, 44.28 percent long-term debt, 2.55 percent short-term debt, and 0.66 percent debt equivalence for off-balance sheet obligations. The 52.51 percent, on a financial basis, falls within the common equity guideline of 50 to 55 percent.

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.

The utility's needs must take precedence over non-utility needs if ratepayers are to be protected. The Commission is responsible for protecting ratepayers from utilities that grant a higher priority to non-utility needs. The identification of utility needs goes beyond foreseeable needs. NSPW must have flexibility to finance both foreseen and unforeseen capital requirements.

The Commission recognizes 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 standard dividends, including pass-through of subsidiary dividends, if its calendar-year average common equity ratio, on a financial basis, is or will fall below the test-year authorized target level of 52.50 percent.

Regulatory Capital Structure and Cost of Capital

Commission staff deducted from NSPW'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 ratemaking capital structure for the purpose of establishing just and reasonable rates for the test year consist of 52.54 percent equity, 44.92 percent long-term debt, and 2.54 percent short-term debt.

Short-Term Debt

NSPW's test-year capital structure contains approximately $31,078,719 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 0.40 percent. This forecast is based on the average of test-year commercial paper rate estimates provided by the *Blue Chip Financial Indicators*. This is a reasonable and objective method of determining NSPW's short-term debt costs. Excluded from this cost are the administrative costs associated with the commercial paper program, which will be treated as an administrative expense rather than as an administrative adder to the interest rate.

Long-Term Debt

NSPW's test-year long-term debt included $150,000,000 of indebtedness proposed to be issued during the test year. A reasonable interest rate for the proposed bonds is 5.20 percent. The resulting embedded cost of long-term debt is 5.71 percent for the test year.

Return on Common Equity

The principle factor used to determine the appropriate return on equity is the investors' required return. Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility ratepayers who ultimately are responsible for paying for those returns. If the investors' required return could be measured precisely, setting the authorized return would be straightforward. Because the return cannot be measured precisely, determining the appropriate return on equity is typically one of the most contested issues in a rate proceeding. In this proceeding, NSPW proposed a rate of return of 10.40 percent. Commission staff suggested that the appropriate return on equity be set somewhere in the range from 10.00 to 10.40 percent and used 10.20 percent in its revenue requirement calculation.

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers. Among the considerations this Commission takes into account is that, while the financial models show that the required returns are declining, NSPW has entered into a major construction phase. Balance is struck most reasonably in this proceeding by authorizing a return on equity capital of 10.20 percent. A

10.20 percent return should allow NSPW to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs.

Capitalization Ratios

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

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$643,331	52.54%	10.20%	5.36%
Long-Term Debt	549,919	44.92	5.71	2.56
Short-Term Debt	31,079	2.54	0.40	0.01
Total Utility Capital	$1,224,328	100.00%		7.93%

The weighted cost of capital of 7.93 percent is reasonable for NSPW for the test year. It generates an economic cost of capital of 11.52 percent and a pre-tax interest coverage ratio of 4.48 times on the regulatory and financial capital structures.

Revenue Requirement

On the basis of the findings in this Final Decision, a $19,537,995 increase in Wisconsin retail electric utility revenues and no increase in Wisconsin retail natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Retail Electric	Retail Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	7.03%	8.34%
Required Return on Average net Investment Rate Base	8.34%	8.34%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	1.31%	0.00%
Average Net Investment Rate Base (000's)	$896,151	$90,020
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	$11,703	$0
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$19,538	$0

Electric Cost-of-Service Studies

Both NSPW and Commission staff submitted the results of several COSS. 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 COSS as a guide along with other factors in its decisions regarding the allocation of revenue responsibility. In this proceeding, the Commission finds that it is reasonable to continue its past practice of relying on the results of more than one COSS, 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 range of increases within 0.7 percent of its overall 6.5 percent electric increase for all of the major customer classes, but decreases for some of the lighting classes. Commission staff's alternative was similar, but included a slightly wider range of increases within 1.0 percent of its overall 3.78 percent electric increase, except for decreases for some of the lighting classes similar to NSPW's proposal.

The Commission routinely considers factors other than COSS 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 an approximate across-the-board increase to all of the major classes is a reasonable allocation of the overall 3.1 percent increase in electric revenue, with approximately 1.3 percent increases for the transmission voltage customers and 3.4 to 3.9 percent increases for the lower voltage customers in the Cg-9 and Cp-1 customer classes. The increases for each of the customer classes are shown in Appendix B.

Electric Rate Design

NSPW proposed a rate design that included increases in energy charges, demand charges and lighting charges, for the various customer classes. The most contentious rate design issues affected NSPW's largest customers. NSPW proposed larger percentage increases for the demand charge revenue than for the energy charge revenue, increases in the high load factor credits, and no changes in the voltage discounts.

Commission staff's alternative rate design also included increases for the demand charge revenue that was greater than the increases in the energy charge revenue, but not as much as NSPW proposed. Commission staff also included identical increases in the high load factor credit and no increase for the voltage discounts in its rate design. Both NSPW's and Commission staff's rate design included increases in the energy charges, no increase in the customer charges for the non-demand customer classes and both increases and decreases to the various lighting classes.

The Wisconsin Industrial Energy Group (WIEG) supported NSPW's electric rate design for the Cg-9, Cp-1, and the RTP-1 classes, but argued for a zero increase for the high voltage customers in these classes. WIEG supported the increases in high load factor credits and argued for increases in the voltage discounts for the transmission level customers to get to a zero increase for these customers. NSPW agreed that a modest increase in the voltage discounts for the transmission level customers is reasonable, but not the increase suggested by WIEG.

The Commission determines that NSPW's proposed changes in the demand and energy charges for the commercial and industrial customers, along with an increase in the voltage discount to 9 percent for the highest transmission voltage level customers and a corresponding adjustment for the other transmission voltage discount, as adjusted for the final revenue requirement, are reasonable. The Commission also determines that NSPW's proposed changes in the energy and lighting charges for the residential, small commercial, lighting and miscellaneous classes, as adjusted for the final revenue requirement, are reasonable. The authorized electric rates also include changes in the 2005 Wisconsin Act 141 rate factors that are consistent with the Commission staff's sales forecast. The authorized electric rates are shown in Appendix B.

Electric Tariff Changes

NSPW proposed changes to its electric Distribution Extension Allowances that are shown in Ex-NSPW-Marx-1, Schedule 6. The distribution extension allowances are part of NSPW's electric rule and regulation tariffs. NSPW also proposed some wording changes to several other electric tariffs that are shown in Ex-NSPW-Dahl-4. There were no objections to these changes, except the changes affecting the Net Energy Billing, Pg tariffs. The Commission finds it reasonable to approve the proposed changes to NSPW's electric tariffs, other than the changes affecting the Net Energy Billing, Pg tariffs.

Customer-Owned Distributed Generation

NSPW proposed to transition Pg-1 Net Energy Billing (NEB) customers grandfathered under the retail rate credit of the Pg-1 tariff in effect prior to January 1, 2011, to the newer Pg-1 tariff net energy credit rate structure effective January 1, 2014. NSPW indicated that it believes its previous extension of the old NEB flat rate by an additional year is a fulfillment of the Commission's earlier discussion and directive to consider potential stranded investment by customers. Commission staff noted the Commission's intent in prior proceedings was not to set a date-certain transition schedule for incorporating grandfathered Pg-1 customers into the new tariff structure, but rather, to lay over this issue, and address the question of customer transition in a future proceeding. Commission staff proposed an alternate transition date, consistent with the transition schedule authorized for Wisconsin Public Service Corporation in that utility's 2014 test-year rate case. Under Commission staff's proposal, affected Pg-4 customers would continue to receive the grandfathered credit treatment through December 31, 2021, at which point those customers would be transitioned to the net energy credit structure of the Pg-4 tariff in effect at the time.

As indicated by Commission staff's bill impact analysis, a majority of the grandfathered Pg-1 customers will likely see little to no change once transitioned to the currently authorized net energy credit structure. Of those who are anticipated to be negatively impacted by the transition, most have been able to benefit from Pg-1 credits at the retail rate since at least 2009. Moreover, the Commission believes that these customers have received sufficient notice over the course of NSPW's last two rate cases regarding a potential change to the net energy credit treatment they receive under the Pg-1 tariff. In addition, the Commission finds that the adverse bill impacts this small number of customers may experience do not sufficiently outweigh the Commission's concerns regarding the potential for cross-subsidization by non-participating ratepayers. The Commission finds it reasonable to extend the grandfathering treatment through 2014 and allow customers who initiated service under the Pg-1 tariff prior to January 1, 2011, with less than 20 kW name plate capacity to continue to be paid for their net monthly excess generation at their full retail rates until January 1, 2015. It is reasonable to then transition these customers to the terms of the Pg-1 tariff in effect at the time.

Commissioner Callisto dissents.

NSPW proposed to add language to the Pg-1 tariff indicating that "all excess generation produced during on-peak hours will be carried forward to the end of the year and will be netted against all usage during on-peak periods. If there is excess on peak generation remaining after the netting of on-peak usage, the customer will receive payment for that excess on-peak generation at the on-peak price as described in the Pg-2A tariff." NSPW's proposal would have the effect of segregating on- and off-peak "buckets" of energy, with on-peak generation only net against on-peak consumption, and off-peak generation only net against off-peak consumption. NSPW argued that this proposal would better align the Pg-1 net energy credits with market prices and would improve price transparency for distributed generation resources. NSPW further argued that its proposed treatment would benefit customers by tying on-peak surplus generation to on-peak usage and on-peak pricing, allowing the customer to benefit as the Pg-2a on-peak price increases, possibly substantially, due to higher projected locational marginal pricing costs. Commission staff objected to this treatment, noting the relatively larger negative impact on TOU customers as compared to flat rate customers, and argued that NSPW's proposal was inconsistent with the Commission's Final Decision in docket 4220-UR-117. Commission staff proposed an alternative that would apply an on/off-peak conversion factor, based on the TOU rates of the customer's standard service tariff, during the annual netting true-up. NSPW objected to Commission staff's proposal, claiming it to be cumbersome and administratively burdensome.

In addition, NSPW argued that Commission staff's proposal would violate the fairness and transparency principles NSPW indicates it is intending to promote through its proposal.

The Commission finds NSPW's arguments persuasive. Therefore, NSPW's proposed Pg-1 language related to the treatment of on-peak and off-peak energy is reasonable.

Commissioner Callisto dissents.

Natural Gas Cost-of-Service Studies

NSPW performed three COSS, using the same methodology, based on three different revenue requirements. The COSS were performed based on NSPW's requested increase of $4,731,000 and Commission staff's proposed revenue decrease of $1,080,000. Additionally, a COSS was performed based on no change in revenue.

It is reasonable to rely on all of the natural gas COSS presented in this docket as guides to setting rates. This has been the Commission's policy in the past and continues to be an appropriate policy.

Natural Gas Distribution Service and Gas Supply Service Rates

Commission staff presented a rate design based on its proposed distribution service revenue decrease of $1,080,000. NSPW provided a rate design based on its requested distribution service increase of $4,731,000, however revised its initial rate design by providing an "Alternative One" rate design based on Commission staff's proposed distribution revenue decrease of $1,080,000. NSPW also proposed an "Alternative 2" rate design that could be used if the Commission approved no change in distribution revenue. All of the proposed rate designs incorporated a reallocation of gas supply costs that transferred approximately $233,000 of gas supply costs from firm system supply customers to interruptible system supply customers.

The Commission finds it reasonable to increase the amortization of MGP cleanup costs to eliminate the excess natural gas revenue. Increasing the MGP amortization will keep natural gas rates flat, mitigate future rate impacts, and avoid customer confusion. The Commission further determines that it is appropriate to make no change in distribution service rates in this proceeding because there is no change in distribution service revenue. Additionally, gas supply costs are not being reallocated in this rate case.

Other Natural Gas Tariff Changes

The Commission approves the following tariff changes that NSPW and Commission staff agreed were reasonable:

- Eliminate the NGV gas supply tariff because no customers have taken service under the tariff recently, no potential customers have expressed interest in the tariff, and NGV refueling stations will continue to have other gas supply service options available.
- Eliminate the interruptible system supply flex-up provision from the SSI-1 Interruptible System Supply tariff because changes in the natural gas marketplace have taken place since it was put in place in 1996, and the provision has hardly been used in recent years.
- Add language to the extension rules that clarifies that a customer may have to pay excess construction costs under certain circumstances.
- Remove language from the natural gas rules that refers to a deferred payment agreement form that was removed from the tariff book as part of rate case docket 4220-UR-108.
- Eliminate all references to transition costs because transition costs are no longer being collected from natural gas customers.

Order

1. This Final Decision shall take effect one day after the date of service.

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect January 1, 2014, 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 shall 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 tariff provisions for natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendix B or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

4. The authorized rate decreases and tariff provisions that expand the terms of service shall take effect January 1, 2014. NSPW shall file these rate decreases and tariff provisions with the Commission and place them in all offices and pay stations of the utility by that date.

5. By January 1, 2014, NSPW shall revise its existing rates and tariff provisions for electric and tariff provisions for natural gas utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendix B or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

6. NSPW shall prepare bill inserts that properly identify the rates authorized in this Final Decision. NSPW shall distribute these inserts to customers with the first billing containing

the rates authorized in this Final Decision and shall file copies of the inserts with the Commission before it distributes the inserts to customers.

7. NSPW shall amortize MGP site clean-up costs in the annual amount of $4,718.704.

8. NSPW shall submit quarterly reports to the Commission detailing the MPUC review of the Monticello Nuclear Plant EPU/LMC cost overruns.

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

10. The electric fuel costs in Appendix C shall be used for monitoring of the NSPW system's 2014 fuel costs, pursuant to Wis. Admin. Code § PSC 116.06(3).

11. An annual bandwidth of plus or minus 2 percent shall be used to monitor fuel costs.

12. The unadjusted New York Mercantile Exchange future prices shall be used to forecast commodity costs not covered by contracts.

13. Fuel costs shall be updated to reflect market prices for coal, natural gas, electricity, and heating oil as of November 13, 2013.

14. Commission staff's proposal to depart from the traditional most recent five-calendar year (2008-2012) EFOR for Sherco Unit 3 and the nuclear units shall be adopted.

15. The 2014 test-year budget for NSPW's conservation escrow shall be $11,023,869 with $9,167,607 allocated to electric and $1,856,262 allocated to natural gas.

16. NSPW shall work with Commission staff to develop metrics of success for the 2014 CSC activities and services approved by the Commission. NSPW and Commission staff shall agree upon the CSC measures of success by January 31, 2014, or the issue shall be returned to the Commission for further consideration.

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

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

19. 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 PPA 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 documentation when S&P and other major credit rating agencies documentation is not available.

20. NSPW shall not pay dividends, including pass-through of subsidiary dividends, in excess of $33,325,000, 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.

21. Jurisdiction is retained.

Dated at Madison, Wisconsin, this 20th day of December, 2013.

By the Commission:

Sandra J. Paske

Sandra J. Paske
Secretary to the Commission

JJB:cmk:DL: 00895416

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 the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service 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 the date of service 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 the date of service 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 serves its original decision.[1] 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: March 27, 2013

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

APPENDIX A

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.

NORTHERN STATES POWER COMPANY – WISCONSIN
John Wilson
Michael Best & Friedrich
One South Pinckney Street, Suite 700
Madison, WI 53703
(Phone: 608-283-4433)
(Email: jdwilson@michaelbest.com; Mara.N.Koeller@xcelenergy.com)

CITIZENS UTILITY BOARD
Kira E. Loehr
Kurt Runzler
Dennis Dums
16 North Carroll Street, Suite 640
Madison, WI 53703
(Phone: 608-251-3322 / Fax: 608-251-7609)
(Email: loehr@wiscub.org; runzler@wiscub.org; dums@wiscub.org)

CONSTELLATION NEWENERGY-GAS DIVISION, LLC
Darcy Fabrizius
N21 W23340 Ridgeview Parkway
Waukesha, WI 53188
(Phone: 262-506-6600 / Fax: 262-506-6611)
(Email: darcy.fabrizius@constellation.com; lisa.simpkins@constellation.com)

RENEW WISCONSIN
Michael Vickerman
222 South Hamilton Street
Madison, WI 53703
(Phone: 608-255-4044)
(Email: mvickerman@renewwisconsin.org)

Docket 4220-UR-119

WISCONSIN INDUSTRIAL ENERGY GROUP
Steven A. Heinzen
Godfrey & Kahn, S.C.
PO Box 2719
Madison, WI 53701-2719
(Phone: 608-257-3911 / Fax: 608-257-0609)
(Email: sheinzen@gklaw.com; tstuart@wieg.org)

WISCONSIN PAPER COUNCIL
Earl Gustafson
5485 Grande Market Drive, Suite B
Appleton, WI 54913
(Phone: 920-574-3752 / Fax: 920-202-3654)
(Email: gustafson@wipapercouncil.org)

PUBLIC SERVICE COMMISSION OF WISCONSIN
(Not a party, but must be served)
610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854
Please file documents using the Electronic Regulatory Filing (ERF) system, which may be accessed through the PSC website: https://psc.wi.gov.

Arielle Silver Karsh
Christina Keeley
Public Service Commission of Wisconsin
610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854
(Silver Karsh Phone: 608-266-7165)
(Keeley Phone: 608-267-7915)
(Email: Arielle.SilverKarsh@wisconsin.gov, Christina.Keeley@wisconsin.gov)

NORTHERN STATES POWER COMPANY (WISCONSIN)

SUMMARY OF ELECTRIC REVENUE
FOR TEST YEAR 2014

INDIVIDUAL RATE CLASSES / SUB-CLASSES	PRESENT REVENUES	AUTHORIZED REVENUES	DOLLAR INCREASE	PERCENT INCREASE
Rg-1 (Residential)	$ 213,570,684	$ 220,178,724	$ 6,608,040	3.09%
Rg-2 (Residential - Optional Time-of-Day)	10,344,181	10,665,554	321,373	3.11%
Fg-1 (Farm Service)	9,637,397	9,951,102	313,705	3.26%
Cg-6 (Optional Off-Peak Service -- Res.)	94,714	97,570	2,856	3.02%
S-1 (Automatic Protective Lighting -- Res.)	457,368	471,679	14,311	3.13%
Cg-1 (Small General - Optional Time-of-Day)	469,108	483,961	14,853	3.17%
Cg-2 (Small General Non-TOD)	44,259,112	45,659,626	1,400,514	3.16%
S-1 (Automatic Protective Lighting -- Com.)	556,380	573,684	17,304	3.11%
Ms-6 (Underground Area Lighting - Private)	36,004	37,115	1,111	3.09%
Ms-2 (Company Owned Street Lighting)	3,584,717	3,696,184	111,467	3.11%
Ms-3 (Cust. Owned Incand./Fluor. Lighting)	3,738	3,854	116	3.10%
Ms-4 (Customer Owned Lighting)	418,627	431,663	13,036	3.11%
Ms-6 (Underground Area Lighting - Public)	283,230	291,976	8,746	3.09%
Ms-7 (Metered - Customer Owned Lighting)	158,119	163,004	4,885	3.09%
Mp-1 (Municipal Water Pumping)	1,178,573	1,217,260	38,687	3.28%
Mz-3 (Fire Siren Service)	2,455	2,455	0	0.00%
VRE (Voluntary Renewable Energy - Windsource)	149,056	144,704	(4,352)	-2.92%
Pg-2 (Parallel Generation Service)	331	331	0	0.00%
Cg-6 (Optional Off-Peak Service -- C&I)	243,137	250,961	7,824	3.22%
Cg-7 (General Service TOD)	89,847,620	92,635,294	2,787,673	3.10%
Cp-3 (Peak Controlled Non-TOD)	3,158,314	3,261,056	102,742	3.25%
DS-1 (Military Fac. Distrib. Service)	514,408	529,862	15,454	3.00%
Cg-9 (Large General TOD)				
Cg-9 Secondary	135,063,280	139,661,358	4,598,078	3.40%
Cg-9 Primary	36,486,186	37,683,083	1,196,897	3.28%
Cg-9 Transmission Transformed	8,202,124	8,308,005	105,880	1.29%
Cg-9 Transmission Untransformed	1,421,373	1,440,185	18,812	1.32%
Cg-9 Subtotal:	**181,172,963**	**187,092,630**	**5,919,667**	**3.27%**
Cp-1 (Peak Controlled Service)				
Cp-1 Secondary	23,202,116	24,051,457	849,342	3.66%
Cp-1 Primary	14,732,906	15,310,990	578,084	3.92%
Cp-1 Transmission Transformed	17,507,311	17,744,274	236,962	1.35%
Cp-1 Subtotal:	**55,442,333**	**57,106,721**	**1,664,388**	**3.00%**
RTP-1 (Real-Time Pricing) Transmission	12,471,400	12,639,981	168,581	1.35%
TOTAL ELECTRIC RETAIL SALES	628,053,970	647,586,951	19,532,981	3.11%
Interdepartmental Sales	163,399	168,494	5,095	3.12%
TOTAL ELECTRIC	**$ 628,217,369**	**$ 647,755,445**	**$ 19,538,076**	**3.11%**

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	12.2600	¢	12.6750	¢
	Non-Summer	11.0900	¢	11.4650	¢
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)	22.8420	¢	23.6030	¢
	On-Peak (Non-Summer)	21.0940	¢	21.7970	¢
	Off-Peak (Summer)	5.8390	¢	6.0330	¢
	Off-Peak (Non-Summer)	5.8390	¢	6.0330	¢
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	12.2600	¢	12.6750	¢
	Non-Summer	11.0900	¢	11.4650	¢
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	12.2600	¢	12.6750	¢
	Non-Summer	11.0900	¢	11.4650	¢
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)	22.8420	¢	23.6030	¢
		21.0940	¢	21.7970	¢
	Off-Peak (Summer)	5.8390	¢	6.0330	¢
		5.8390	¢	6.0330	¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
GENERAL SERVICE, Cg-5 (Closed)			
Customer Charge (per Month):		$30.00	$30.00
Demand Charges (per kW):	Secondary (Summer)	$11.95	$12.25
	Secondary (Non-Summer)	$9.95	$10.25
	Primary (Summer)	$11.36	$11.64
	Primary (Non-Summer)	$9.40	$9.68
Energy Charge (per kWh)	Summer	6.3275 ¢	6.5200 ¢
	Non-Summer	5.7577 ¢	5.9700 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.59	$0.61
[Discounts Reflected Above]	Non-Summer	$0.55	$0.57
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.9000 ¢	1.0000 ¢
PEAK CONTROLLED SERVICE, Cp-2 (Closed)			
Customer Charge (per Month):		$40.00	$40.00
Demand Charges (per kW):			
Firm Demand:	Secondary (Summer)	$11.95	$12.25
	Secondary (Non-Summer)	$9.95	$10.25
	Primary (Summer)	$11.36	$11.64
	Primary (Non-Summer)	$9.40	$9.68
Controlled Demand:	Secondary (Summer)	$7.05	$7.35
	Secondary (Non-Summer)	$7.05	$7.35
	Primary (Summer)	$6.56	$6.84
	Primary (Non-Summer)	$6.56	$6.84
Energy Charge (per kWh)	Summer	6.3275 ¢	6.5200 ¢
	Non-Summer	5.7577 ¢	5.9700 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.59	$0.61
[Discounts Reflected Above]	Non-Summer	$0.55	$0.57
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.900 ¢	1.000 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
TOD GENERAL SERVICE, Cg-7			
Customer Charge (per Month):		$30.00	$30.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$11.95	$12.25
	Secondary (Non-Summer)	$9.95	$10.25
	Primary (Summer)	$11.36	$11.64
	Primary (Non-Summer)	$9.40	$9.68
Energy Charge (per kWh)	On-Peak (Summer)	6.3275 ¢	6.7630 ¢
	On-Peak (Non-Summer)	5.7577 ¢	6.2130 ¢
	Off-Peak (Summer)	6.3275 ¢	5.9750 ¢
	Off-Peak (Non-Summer)	5.7577 ¢	5.9750 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.59	$0.61
[Discounts Reflected Above]	Non-Summer	$0.55	$0.57
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.9000 ¢	1.0000 ¢
TOD PEAK CONTROLLED SERVICE, Cp-3			
Customer Charge (per Month):		$40.00	$40.00
Demand Charges (per kW):			
Firm Demand:	Secondary (Summer)	$11.95	$12.25
	Secondary (Non-Summer)	$9.95	$10.25
	Primary (Summer)	$11.36	$11.64
	Primary (Non-Summer)	$9.40	$9.68
Controlled Demand:	Secondary (Summer)	$7.05	$7.35
	Secondary (Non-Summer)	$7.05	$7.35
	Primary (Summer)	$6.56	$7.20
	Primary (Non-Summer)	$6.56	$7.20
Energy Charge (per kWh)	On-Peak (Summer)	6.3275 ¢	6.7630 ¢
	On-Peak (Non-Summer)	5.7577 ¢	6.2130 ¢
	Off-Peak (Summer)	6.3275 ¢	5.9750 ¢
	Off-Peak (Non-Summer)	5.7577 ¢	5.9750 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.59	$0.61
[Discounts Reflected Above]	Non-Summer	$0.55	$0.57
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.900 ¢	1.000 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
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)	5.3720 ¢	5.5500 ¢
	Secondary (Non-Summer)	5.3720 ¢	5.5500 ¢
	Primary (Summer)	5.2646 ¢	5.4390 ¢
	Primary (Non-Summer)	5.2646 ¢	5.4390 ¢
Non-Authorized Use Charge (per kWh)		22.4020 ¢	23.1640 ¢
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)	$10.45	$11.16
	Secondary (Non-Summer)	$8.45	$9.16
	Primary (Summer)	$10.24	$10.94
	Primary (Non-Summer)	$8.28	$8.98
	Trans. Transformed (Sum.)	$9.72	$10.21
	Tr. Transform. (Non-Sum.)	$7.86	$8.38
	Transmission (Summer)	$9.67	$10.16
	Transmission (Non-Sum.)	$7.82	$8.34
Customer Demand Charges (per kW):	Secondary	$1.39	$1.48
	Primary	$1.04	$1.11
	Trans. Transformed	$0.59	$0.63
	Transmission	$0.00	$0.00
Energy Charge (per kWh):	On-Peak (Summer)	8.0210 ¢	8.1590 ¢
	On-Peak (Non-Summer)	7.2350 ¢	7.3590 ¢
	Off-Peak (Summer)	4.7300 ¢	4.8110 ¢
	Off-Peak (Non-Summer)	4.7300 ¢	4.8110 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	7.00%	8.50%
	Transmission	7.50%	9.00%
Voltage Discounts = [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.21	$0.22
	Primary (Non-Summer)	$0.17	$0.18
	Trans. Transformed (Sum.)	$0.73	$0.95
	Tr. Transform. (Non-Sum.)	$0.59	$0.78
	Transmission (Summer)	$0.78	$1.00
	Transmission (Non-Sum.)	$0.63	$0.82
Customer (per kW):	Primary	$0.35	$0.37
	Trans. Transformed	$0.80	$0.85
	Transmission	$1.39	$1.48
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.9000 ¢	1.0000 ¢

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)	$10.45	$11.16
	Secondary (Non-Summer)	$8.45	$9.16
	Primary (Summer)	$10.24	$10.94
	Primary (Non-Summer)	$8.28	$8.98
	Trans. Transformed (Sum.)	$9.72	$10.21
	Tr. Transform. (Non-Sum.)	$7.86	$8.38
	Transmission (Summer)	$9.67	$10.16
	Transmission (Non-Sum.)	$7.82	$8.34
Customer Demand Charges (per kW):	Secondary	$1.39	$1.48
	Primary	$1.04	$1.11
	Trans. Transformed	$0.59	$0.63
	Transmission	$0.00	$0.00
Controlled Demand Charges (per kW):	Secondary (Summer)	$5.55	$6.26
	Secondary (Non-Summer)	$5.55	$6.26
	Primary (Summer)	$5.44	$6.14
	Primary (Non-Summer)	$5.44	$6.14
	Trans. Transformed (Sum.)	$5.16	$5.73
	Tr. Transform. (Non-Sum.)	$5.16	$5.73
	Transmission (Summer)	$5.14	$5.70
	Transmission (Non-Sum.)	$5.14	$5.70
Energy Charge (per kWh):	On-Peak (Summer)	8.0210 ¢	8.1590 ¢
	On-Peak (Non-Summer)	7.2350 ¢	7.3590 ¢
	Off-Peak (Summer)	4.7300 ¢	4.8110 ¢
	Off-Peak (Non-Summer)	4.7300 ¢	4.8110 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	7.00%	8.50%
	Transmission	7.50%	9.00%
Voltage Discounts [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.21	$0.22
	Primary (Non-Summer)	$0.17	$0.18
	Trans. Transformed (Sum.)	$0.73	$0.95
	Tr. Transform. (Non-Sum.)	$0.59	$0.78
	Transmission (Summer)	$0.78	$1.00
	Transmission (Non-Sum.)	$0.63	$0.82
Customer (per kW):	Primary	$0.35	$0.37
	Trans. Transformed	$0.80	$0.85
	Transmission	$1.39	$1.48
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.900 ¢	1.000 ¢

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)		$4.66	$4.80

EXPERIMENTAL REAL TIME PRICING, RTP-1

Customer Charge (per Month)		$300.00	$300.00
Contract Demand Charges (per kW):	Secondary	$9.12	$9.83
	Primary	$8.93	$9.63
	Trans. Transformed	$8.48	$8.99
	Transmission	$8.44	$8.95
Distribution Demand Charges (per kW):	Secondary	$1.39	$1.48
	Primary	$1.04	$1.11
	Trans. Transformed	$0.59	$0.63
	Transmission	$0.00	$0.00
Energy Charges (per kWh):		Authorized Hourly Energy Prices included in the table below	
Approx. Act 141 $ in Large Energy Customer Rates		0.000 ¢	0.000 ¢
Energy Voltage Discounts (per kWh):	Primary	0.110 ¢	0.113 ¢
	Trans. Transformed	0.376 ¢	0.479 ¢
	Transmission	0.403 ¢	0.508 ¢
Limited Energy Surcharge (per kWh)		11.6500 ¢	11.9487 ¢
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.9000 ¢	1.0000 ¢

Energy Chgs. $ per kWh	Day Types							
	1	2	3	4	5	6	7	8
12 am - 6 am	0.05645	0.05123	0.04866	0.04398	0.04151	0.03697	0.03663	0.03482
6 am - 9 am	0.09745	0.08012	0.06576	0.06668	0.06369	0.04800	0.04755	0.04035
9 am - 12 pm	0.25335	0.17539	0.11046	0.08782	0.07246	0.06201	0.05088	0.04395
12 pm - 6 pm	0.42220	0.27931	0.16242	0.10080	0.07246	0.06201	0.05088	0.04395
6 pm - 9 pm	0.30530	0.22735	0.13644	0.08965	0.07246	0.06201	0.05088	0.04395
9 pm - 12 pm	0.09535	0.07719	0.06928	0.06161	0.05098	0.04562	0.04176	0.03919

AUTOMATIC PROTECTIVE LIGHTING, S-1

Monthly Charges (per Unit):		
175 Watt MV Lamps (Closed)	$9.09	$9.37
250 Watt MV Lamps (Closed)	$12.10	$12.48
400 Watt MV Lamps (Closed)	$16.28	$16.78
70 Watt HPS Lamps	$6.49	$6.69
100 Watt HPS Lamps	$7.90	$8.15
150 Watt HPS Lamps	$9.54	$9.84
250 Watt HPS Lamps	$12.93	$13.33
400 Watt HPS Lamps	$18.49	$19.06

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)	$13.28	$13.69
250 Watt MV Lamps (Closed)	$15.12	$15.59
400 Watt MV Lamps (Closed)	$18.70	$19.28
70 Watt HPS Lamps	$10.90	$11.24
100 Watt HPS Lamps	$11.89	$12.26
150 Watt HPS Lamps	$13.24	$13.65
250 Watt HPS Lamps	$16.47	$16.98
400 Watt HPS Lamps	$21.41	$22.07
Underground:		
175 Watt MV Lamps (Closed)	$19.45	$20.05
250 Watt MV Lamps (Closed)	$21.17	$21.83
70 Watt HPS Lamps	$16.32	$16.83
100 Watt HPS Lamps	$17.31	$17.85
150 Watt HPS Lamps	$18.67	$19.25
250 Watt HPS Lamps	$22.15	$22.84
400 Watt HPS Lamps	$26.83	$27.66
Decorative Underground:		
100 Watt HPS Lamps	$34.65	$35.72
150 Watt HPS Lamps	$36.21	$37.33
250 Watt HPS Lamps	$39.36	$40.58
400 Watt HPS Lamps	$43.94	$45.30
Maintenance Option:		
100 Watt HPS Lamps	$8.84	$9.11
150 Watt HPS Lamps	$10.55	$10.88
250 Watt HPS Lamps	$13.91	$14.34
400 Watt HPS Lamps	$18.80	$19.38

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)	$7.38	$7.61
250 Watt MV Lamps (Closed)	$9.07	$9.35
400 Watt MV Lamps (Closed)	$12.87	$13.27
700 Watt MV Lamps (Closed)	$20.36	$20.99
50 Watt HPS Lamps	$4.47	$4.61
70 Watt HPS Lamps	$4.98	$5.13
100 Watt HPS Lamps	$5.94	$6.12
150 Watt HPS Lamps	$7.05	$7.27
250 Watt HPS Lamps	$10.32	$10.64
400 Watt HPS Lamps	$14.14	$14.57
Group I - Energy and Maintenance (No Paint):		
175 Watt MV Lamps (Closed)	$7.13	$7.36
250 Watt MV Lamps (Closed)	$8.82	$9.10
400 Watt MV Lamps (Closed)	$12.62	$13.02
700 Watt MV Lamps (Closed)	$20.11	$20.74
50 Watt HPS Lamps	$4.22	$4.36
70 Watt HPS Lamps	$4.73	$4.88
100 Watt HPS Lamps	$5.69	$5.87
150 Watt HPS Lamps	$6.80	$7.02
250 Watt HPS Lamps	$10.07	$10.39
400 Watt HPS Lamps	$13.89	$14.32
Group II - Energy Only:		
100 Watt MV Lamps (Closed)	$2.87	$2.96
175 Watt MV Lamps (Closed)	$4.59	$4.73
400 Watt MV Lamps (Closed)	$10.12	$10.43
700 Watt MV Lamps (Closed)	$17.28	$17.82
35 Watt HPS Lamps	$0.96	$0.99
50 Watt HPS Lamps	$1.39	$1.43
70 Watt HPS Lamps	$1.84	$1.90
100 Watt HPS Lamps	$2.77	$2.86
150 Watt HPS Lamps	$4.26	$4.39
200 Watt HPS Lamps	$5.41	$5.58
250 Watt HPS Lamps	$6.58	$6.78
400 Watt HPS Lamps	$10.36	$10.68
1000 Watt HPS Lamps	$23.47	$24.20

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		$16.92	$17.44
400 Watt MV Lamps		$20.15	$20.77
150 Watt HPS Lamps		$16.81	$17.33
250 Watt HPS Lamps		$19.92	$20.53
UNDERGROUND AREA LIGHTING, Ms-6			
Monthly Charges (per Lamp):			
175 Watt MV Lamps (Closed)		$17.10	$17.63
100 Watt HPS Lamps		$15.23	$15.70
150 Watt HPS Lamps		$17.37	$17.91
METERED CUSTOMER OWNED STREET LIGHTING, Ms-7			
Customer Charge (per Month)		$7.25	$7.25
Energy Charge (per kWh)		6.2890 ¢	6.4840 ¢
COMPANY OWNED STREET LIGHTING, Ms-3 (Closed)			
Monthly Charges (per Lamp):			
2,500 Lumen - Incand. (AN)		$8.46	$8.72
4,000 Lumen - Incand. (AN)		$10.32	$10.64
6,000 Lumen - Incand. (AN)		$12.44	$12.83
10,000 Lumen - Incand. (AN)		$16.59	$17.10
F72H0 - Fluorescent (4AN)		$16.84	$17.36
F72H0 - Fluor. (2AN+2MN)		$14.82	$15.28
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	12.2600 ¢	12.6750 ¢
	Non-Summer	11.0900 ¢	11.4650 ¢
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 ¢
Voluntary Renewable Energy Rider (WINDSOURCE®), VRE			
Energy Charge Adder		1.37 ¢	1.33 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
HYDRO ENERGY PURCHASE, Pg-1 (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		3.200 ¢	3.620 ¢
PARALLEL GENERATION, Pg-2A, 2B, 2C			
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 adjusted automatically in late 2012 for 2013	Rates adjust automatically in late 2013 for TY 2014
ELECTRIC SERVICE EXTENSION ALLOWANCES			
Residential & Farm Service:			
(for Rg-1, Rg-2, Fg-1)		$499.00	$527.00
General Service -- Non-Demand:			
(for Cg-1, Cg-2, Mp-1, Mz-3)		$532.00	$578.00
General Service -- Demand:			
(for Cg-5 and Cp-2) per kW:		$79.00	$81.00
Large General Service -- Demand:			
(for Cg-9 and Cp-1)			
Secondary (per kW):		$53.00	$52.00
Primary (per kW):		$45.00	$44.00
Street and Area Lighting:			
(for Ms-2, Ms-4, Ms-6)		$108.00	$171.00
Act 141 Cost in Base Rates (per kWh)			
For Rg-1, Rg-2, & Fg-1		0.1400 ¢	0.1480 ¢
For Cg-1 thru Cg-9, Cp-1 thru Cp-2, S-1 & Ms-1 thru Ms-7		0.1280 ¢	0.1250 ¢
Approx. Act 141 $ in Large Energy Customer Rates		Specific to each customer	

Northern States Power Company-Wisconsin
Docket 4220-UR-119
Monitored Fuel Costs for 2014

	Total Fuel Rules Cost	System Requirements	Monthly $/kWh	Cumulative $/kWh
January	$ 99,186,624	3,913,590,666	$ 0.02534	$ 0.02534
February	87,154,825	3,439,302,366	$ 0.02534	$ 0.02534
March	91,469,256	3,607,723,070	$ 0.02535	$ 0.02535
April	81,730,311	3,307,244,004	$ 0.02471	$ 0.02520
May	86,431,820	3,502,518,111	$ 0.02468	$ 0.02510
June	95,895,175	3,843,673,621	$ 0.02495	$ 0.02507
July	112,018,816	4,324,081,565	$ 0.02591	$ 0.02521
August	105,608,574	4,175,703,602	$ 0.02529	$ 0.02522
September	88,044,014	3,569,781,645	$ 0.02466	$ 0.02516
October	88,528,393	3,469,578,844	$ 0.02552	$ 0.02519
November	91,181,800	3,428,975,872	$ 0.02659	$ 0.02531
December	95,325,490	3,796,418,905	$ 0.02511	$ 0.02530
Total	$ 1,122,575,098	44,378,592,271	$ 0.02530	