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PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	6690-UR-122

FINAL DECISION

This is the Final Decision in the application of Wisconsin Public Service Corporation (WPSC) for authority to increase Wisconsin retail electric and natural gas rates in 2014.

Final electric rate changes are authorized consisting of a $9,835,000 increase offset against a portion of estimated fuel cost over-collections in 2013 of the same amount and an electric revenue stabilization mechanism (RSM) credit from 2012 over-collections of $12,764,000 returned to RSM rate classes in 2014. The overall rate changes provide a $12,764,000 annual rate decrease for Wisconsin retail electric operations, a 1.32 percent decrease. Final natural gas rate changes are authorized consisting of a $3,881,000 decrease offset against a natural gas RSM charge from 2012 under-collections of $7,877,000. The overall rate changes provide a $3,996,000 annual rate increase for Wisconsin retail natural gas operations, a 1.23 percent increase.

Introduction

On March 29, 2013, WPSC filed a request for authority to increase its Wisconsin retail electric rates by $71,108,000, a 7.36 percent increase, and to increase its Wisconsin retail natural gas rates by $19,010,000, a 5.56 percent increase, to be effective January 1, 2014. These increases are based on a 10.75 percent return on common equity.

The March 29, 2013, WPSC filing included a request to include the impacts of updated employee benefit costs from actuarial analyses expected in late May 2013. The resulting analyses indicated an additional increase of $4,110,000 on a corporate basis for 2014 electric and natural gas revenue requirements was needed. On June 14, 2013, WPSC requested an additional increase to its 2014 revenue requirements of $1,270,000 expense on a corporate basis for manufactured gas plant remediation costs, $293,000 expense on a corporate basis for electric and natural gas amortization expenses of upfront credit facility fees, and the inclusion of electric revenue requirement associated with additional spending in 2014 for environmental mitigation projects resulting from the U.S. Environmental Protection Agency (EPA) Consent Decree that WPSC entered into in 2013. On August 20, 2013, WPSC requested adjustments to electric and natural gas rate bases and associated revenue requirements related to the deferred tax proration formula that was not included in the March 29, 2013, filing of approximately $700,000. The effects of these requests result in updated rate increase requests in the test year of approximately $75,901,000, a 7.86 percent increase, for Wisconsin retail electric utility operations and $21,236,000, a 6.53 percent increase, for retail natural gas utility operations.

On May 22, 2013, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. On September 27, 2013, public hearings were held in Madison, Wisconsin, for members of the general public and for the parties in this proceeding. On November 14, 2013, the Commission reopened the record in this proceeding to accept further evidence and solicit comments relating to the application of WPSC for authority to adjust its electric and natural gas rates.

The Commission considered this matter at its open meetings of November 6, 2013, November 14, 2013, and November 22, 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. WPSC is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a), providing electric and natural gas service to north-central and northeast Wisconsin.

2. Presently authorized rates for WPSC's Wisconsin retail electric utility operations will produce total operating revenues of $1,031,628,000 for the test year ending December 31, 2014, which results in an adjusted net operating income of $128,739,000 and an annual revenue excess of $2,929,000. Presently authorized rates for WPSC's Wisconsin retail natural gas utility operations will produce total operating revenues of $318,768,000 for the test year ending December 31, 2014, which results in an adjusted net operating income of $25,399,000 and an annual revenue deficiency of $3,996,000.

3. For the Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $1,462,706,000 at current rates subject to the Commission's jurisdiction for the test year is 8.80 percent, which is excessive.

4. For the Wisconsin retail natural gas utility, the estimated rate of return on average net investment rate base of $342,028,000 at current rates subject to the Commission's jurisdiction for the test year is 7.43 percent, which is inadequate.

5. A reasonable decrease in operating revenue for the test year to produce an 8.68 percent return on WPSC's average net investment rate base for Wisconsin retail electric operations is $2,929,000.

6. A reasonable increase in operating revenue for the test year to produce an 8.13 percent return on WPSC's average net investment rate base for natural gas operations is $3,996,000.

7. WPSC's filed operating income statements and net investment rate base for the test year, as adjusted for Commission decision, are reasonable.

8. Commission staff forecasted electric and natural gas sales are reasonable.

9. It is appropriate to offset $9,835,000 of the 2013 fuel cost over-recovery against the 2014 test-year electric utility revenue requirement and reasonable to approve WPSC's 2014 fuel cost plan upon the condition that such 2013 fuel cost over-collections are used as an offset to the 2014 test-year electric rate increase.

10. It is reasonable in this proceeding to forecast fuel costs based on the New York Mercantile Exchange (NYMEX) natural gas futures prices as of November 4, 2013.

11. It is reasonable to set a 2014 fuel plan-year cost of monitored fuel of $374,213,000, or $27.33 per megawatt-hour (MWh), as shown in Appendix D.

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

13. It is reasonable to allow WPSC to recover any incremental emissions compliance costs associated with the consent decrees that may be incurred during 2014, and to be allowed to include those costs in reported monitored fuel costs.

14. It is reasonable to allow WPSC to defer any minimum tonnage obligation costs incurred during 2014 for possible future rate recovery, with the provision that it is required to submit a detailed analysis documenting its efforts to eliminate or minimize these costs when it seeks rate recovery.

15. It is reasonable to incorporate the ratified union wage increases into estimates for union employee payroll expense and reduce benefits expense associated with union benefits concessions in test-year electric and natural gas revenue requirements.

16. It is not reasonable to include incentive pay plans’ costs in test-year electric and natural gas revenue requirements.

17. It is reasonable to include economic development expenses of $304,000 in test-year electric and natural gas revenue requirements.

18. It is reasonable to include deferrals from the settlement in docket 6690-UR-121 in test-year electric and natural gas revenue requirements.

19. It is reasonable to include the revenue requirement impacts of the environmental mitigation project (EMP) costs forecasted to be incurred in 2014 in electric revenue requirement.

20. It is reasonable to terminate the electric RSM and the natural gas RSM beginning January 1, 2014.

21. The reasonable level of expensed conservation costs recoverable in rates for the 2014 test year is $16,644,714 for electric utility operations and $4,263,100 for natural gas utility

operations. The level for electric utility operations consists of the conservation budget of $15,750,854, an escrow amortization adjustment of $894,928, and a net adjustment for miscellaneous corrections of ($1,068). The electric escrow adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2013, over three years. The level for natural gas operations consists of the conservation budget of $5,121,489, an escrow amortization adjustment of ($851,117), and a net adjustment for miscellaneous corrections of ($7,272). The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2013, over three years.

22. Activities and services for which less than 51 percent is related to energy efficiency do not meet the Commission's definition of customer service conservation and are not appropriate for inclusion in the conservation escrow budget.

23. It is appropriate for WPSC to work with Commission staff to develop metrics for the customer service conservation activities approved for inclusion in the conservation escrow.

24. It is reasonable to continue accounting for allowable electric and natural gas conservation expenditures on an escrow basis.

25. It is reasonable to adjust average net investment rate base to reflect amendments to Wisconsin tax law and the elimination of a deferred tax asset related to a net operating loss (NOL).

26. It is reasonable for WPSC to earn a current return on 50 percent of construction work in progress (CWIP).

27. It is reasonable that the allowance for funds used during construction (AFUDC) rate remain at the adjusted weighted cost of capital.

28. It is reasonable for WPSC to earn a current return on the unamortized balances of the De Pere Energy Center (DEC) premium, Crane Creek revenue normalization and production tax credit deferrals, Fox Energy Center purchased power contract buyout, acquisition adjustment, and contract service agreement (CSA) amortization, the Glenmore Wind Asset retirement deferral, and the deferred tax proration adjustment at the authorized weighted average cost of capital.

29. It is reasonable for WPSC to earn a current return on the unamortized balances of the remaining revenue stabilization mechanism deferral, Columbia and Edgewater precertification and preconstruction deferral, the Cross-State Air Pollution Rule (CSAPR) deferral, reductions for two electric fuel refunds, and the remaining balance of additional Focus on Energy (FOE) payments at the authorized short-term debt rate.

30. It is reasonable to record the full amounts of all non-escrowed amortizations in the test year.

31. It is reasonable to include all uncontested Commission staff adjustments to WPSC's filed electric and natural gas income statements and average net investment rate bases.

32. A long-term range of 49 percent to 54 percent for WPSC's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

33. An appropriate target level for the test-year average common equity measured on a financial capital structure basis is 51.0 percent.

34. It is appropriate to limit the amount of equity infusion to the lesser of the amount needed to achieve a test-year average equity ratio, on a financial basis, approximating the target level of 51.0 percent or the amount found not to result in cash or cash equivalent holdings.

35. A reasonable estimate of the amount of debt equivalent to be imputed into WPSC's financial capital structure for the test year is $18,430,000.

36. A reasonable financial capital structure for the test year consists of 51.00 percent common equity, 1.88 percent preferred stock, 43.14 percent long-term debt, 3.31 percent short-term debt, and 0.67 percent debt equivalence for off-balance sheet obligations, including subsidiary debt.

37. It is reasonable to revise WPSC's dividend restrictions based on the capital structure determinations in this proceeding.

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

39. It is reasonable to require WPSC 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.

40. A reasonable utility capital structure for ratemaking for the test year consists of 50.14 percent common equity, 1.94 percent preferred stock, 44.51 percent long-term debt, and 3.41 percent short-term debt.

41. A reasonable return on utility common stock equity is 10.20 percent.

42. A reasonable interest rate for short-term borrowing through commercial paper is 0.40 percent for the test year.

43. A reasonable interest rate for the $450 million long-term debt to be issued in 2013 is 4.50 percent.

44. A reasonable average embedded cost for long-term debt is 4.85 percent for the test year.

45. A reasonable average cost for preferred stock is 6.08 percent for the test year.

46. A reasonable weighted average composite cost of capital is 7.40 percent.

47. It is reasonable to rely on the results of one or more electric cost-of-service studies (COSS) along with other factors, such as bill impacts, when allocating revenue responsibility.

48. The distribution allocation method used in WPSC's COSS is reasonable.

49. It is reasonable to approve the rate changes for electric and natural gas service as shown in Appendices B and C.

50. It is reasonable to maintain the interruptible credits at the current amounts.

51. It is reasonable to maintain the current Real Time Market Pricing adder at this time.

52. It is reasonable to require WPSC to work with the Wisconsin Industrial Energy Group (WIEG) and other appropriate stakeholders to evaluate the energy adder in the Real Time Market Pricing rate schedule.

53. It is reasonable to retain WPSC's existing monthly netting structure for the Pg-4 tariff.

54. It is reasonable for Pg-4 customers to be credited for net surplus generation at the avoided cost rate based on WPSC's Locational Marginal Pricing (LMP) derived Pg-2A rates, plus its avoided cost of transmission.

55. It is reasonable to allow customers who initiated service under the Pg-4 tariff prior to March 31, 2011, and customers who submitted signed applications to WPSC prior to March 31, 2011, with less than or equal to 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, 2021. It is reasonable to then transition these customers to the terms of the Pg-4 tariff in effect at the time.

56. It is reasonable to modify the Pg-4 tariff so as reduce the capacity limit from 100 kW to 20 kW per customer premises, and to limit Pg-4 customers' generation so that the installed capacity does not exceed what is necessary to serve the customer's expected load at the same location.

57. It is reasonable to allow customers with generation capacity greater than 20 kW but less than or equal to 100 kW that was installed after January 13, 2011, and who take service under Pg-4 prior to January 1, 2014, to continue to take service under the Pg-4 tariff provided that they do not increase the generation capacity enrolled. It is reasonable for customers with signed applications for generation capacity greater than 20 kW but less than or equal to 100 kW that are submitted to WPSC prior to January 1, 2014, and who, to the satisfaction of WPSC, have made material financial investments in the project, to take service under the Pg-4 tariff. It is also reasonable for customers who submitted an application prior to January 1, 2014, for FOE grants

for projects with generation capacity greater than 20 kW but less than or equal to 100 kW to take service under the Pg-4 tariff if the grant is awarded and that FOE grant recipients do not increase the generation capacity beyond what was submitted in the grant application.

58. It is reasonable to allow demand-metered customers and response rewards customers to take service under the Pg-4 tariff.

59. It is reasonable to credit Pg-4 customers for WPSC's avoided cost of transmission.

60. It is reasonable to modify the Pg-4 tariff to include language stating that that the customer shall retain all renewable attributes associated with the energy sold to WPSC pursuant to the tariff.

61. It is reasonable to increase the Pg-2 Parallel Generation customer charge from $10.00 to $20.00.

62. The capacity credit proposed by WPSC for the Pg-2A and Pg-2B parallel generation tariffs is reasonable.

63. WPSC's proposed modification of the Pg-2A and Pg-2B loss factors is reasonable.

64. It is reasonable to direct that an in-depth review of market-based buyback rates be conducted in WPSC's next base rate case in order to determine whether those rates are functioning appropriately.

65. At this time it is not reasonable to open an investigation into the costs and system benefits associated with customer-owned generation.

66. It is reasonable to continue to rely on the results of one or more natural gas COSS along with other factors, such as bill impacts, as guides for revenue allocation and rate design.

67. It is appropriate to increase monthly service charges in light of the natural gas COSS and an expiration of the gas RSM.

68. It is reasonable to revise main and service extension rules, minimum payment option rules and late payment provisions as shown in Appendix C.

69. It is reasonable to approve the purchase gas adjustment clause (PGAC) tariff as shown in Appendix C.

70. It is appropriate to limit the applicability of low-flow constraint penalties to WPSC's incurrence of interstate penalty charges and/or cycling fees during a low-flow constraint period. It is reasonable to revise low-flow constraint provisions as shown in Appendix C.

Conclusions of Law

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, and 134 to enter a Final Decision authorizing WPSC to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and 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

WPSC is a public utility, as defined in Wis. Stat. § 196.01(5), engaged in the production, transmission, distribution, and sale of electricity, and in the purchase, distribution, and sale of natural gas in a service area of approximately 11,000 square miles in northeastern Wisconsin and adjacent parts of upper Michigan. Cities that WPSC serves with retail electric service or natural gas service include Green Bay, Marinette, Oshkosh, Rhinelander, Sheboygan, Stevens Point, and Wausau in Wisconsin, and Menominee in Michigan. WPSC is an operating subsidiary of Integrys Energy Group, Inc. (Integrys), a holding company headquartered in Chicago, Illinois.

WPSC also sells electricity at wholesale rates to other utilities and electric cooperatives for resale. The Federal Energy Regulatory Commission regulates these wholesale sales. WPSC's wholesale rates, therefore, are not affected by these proceedings. Similarly, the rates applicable to retail sales of electricity and natural gas to Michigan customers are not subject to the jurisdiction of this Commission and are not affected by these proceedings.

Offsetting of the 2013 Fuel Cost Over-Recoveries Against the Electric Utility Revenue Deficiency in 2014

After the Commission first discussed the record in this proceeding on November 6, 2013, and before it reopened the record in this proceeding, the estimated 2014 electric utility revenue deficiency was $15,449,000 on a Wisconsin retail basis before the electric RSM credit of $12,764,000 was to be applied to RSM rate classes. This deficiency was based on using the NYMEX futures forecasts as of October 15, 2013, to forecast fuel costs. The estimated deficiency was expected to be significantly less than the over-collection of 2013 fuel costs. The Commission reopened the record in this proceeding on November 14, 2013, to accept additional evidence and to solicit comments from the parties and the public. The Commission, consistent with Wis. Stat. § 196.20(4)(c) and Wis. Admin. Code § PSC 116.07(4)(c), solicited comments as to whether the Commission should offset the requested electric rate increase in this case with a portion of expected 2013 fuel over-collections. The Commission also solicited comments on the use of updated NYMEX forecasts as of November 4, 2013, to forecast test-year fuel costs.

WPSC indicated in its comments it was agreeable to an early refund of that portion of its estimated 2013 fuel over-collections needed to achieve the Commission's desired rate design on the condition that the NYMEX futures forecasts not be updated to the November 4, 2013, forecasts. WPSC argued that the Commission's proposal to update the NYMEX forecasts from October 15, 2013, to November 4, 2013, would be inconsistent with the Commission's general practice of using mid-month NYMEX futures prices as the estimate for natural gas prices.

The Citizens Utility Board (CUB) supported the Commission's use of the November 4, 2013, NYMEX futures forecasts, the same date as that used for the Wisconsin Power and Light Company (WP&L) fuel proceeding. CUB also indicated that the record in WPSC's case was not yet closed and in keeping with the Commission's practice of using the NYMEX futures process as of a single day close in time to the Commission's final decision, it should use the November 4, 2013, date instead of the October 15, 2013, date. CUB did not oppose offsetting the electric deficiency with the estimated 2013 fuel cost over-collections in this unique situation, but did not want it to become a common practice.

WIEG supported using the November 4, 2013, NYMEX futures to forecast fuel costs and offsetting the electric deficiency with a portion of the 2013 fuel cost over-collections in light of the significant anticipated 2013 fuel cost over-collections in this specific proceeding. However, as a matter of ongoing practice, WIEG indicated its belief that the Commission should not update the NYMEX futures prices after the Commission's open meeting. WIEG also stated that as a matter of ongoing practice, fuel cost over-collections should not be used as an offset to a revenue requirement deficiency but rather, in most situations, fuel cost over-collections should be returned to ratepayers at the very earliest opportunity.

The Commission accepts the comments received into the record. The Commission also accepts, consistent with Wis. Stat. § 227.45(2), the additional evidence regarding the 2014 Test Year Electric Net Generation Fuel and Purchased Power Costs for Fuel Monitoring using NYMEX estimates updated as of November 4, 2013, and the additional evidence regarding the estimated amount of 2013 fuel over-collections through December 31, 2013.

The use of NYMEX forecasts as of November 4, 2013, results in an estimated 2014 electric utility revenue deficiency of $9,835,000 on a Wisconsin retail basis before the electric RSM credit of $12,764,000 is applied to RSM rate classes. While the Commission has often used mid-month NYMEX futures to forecast future test-year gas costs, the Commission finds it reasonable to use the November 4, 2013, NYMEX forecasts in this specific proceeding. Because of lack of materiality, the coal and heating oil futures prices were not updated from the mid-October prices, and it is reasonable to use these future prices based upon the mid-October prices. The November 4, 2013, date was used in the recent WP&L fuel proceeding in docket 6680-FR-106 to forecast 2014 test-year gas costs, and was discussed at the open meeting of November 14, 2013—the same date that the Commission discussed and reopened the record in this proceeding. Using the updated NYMEX estimates is consistent with the Commission practice of using NYMEX futures prices as of a single date as close in time as possible to the

Commission's final discussion of record. Use of more recent NYMEX futures is also preferable as it results in more reliable estimates upon which to base 2014 fuel cost estimates. Further, there have been a number of previous instances in which the Commission has used NYMEX futures forecast as of dates that were other than mid-month, including prior WPSC rate case proceedings.[1]

The Commission also finds it appropriate to offset a portion of the estimated 2013 fuel cost over-recovery against the 2014 electric revenue deficiency before the application of the RSM credits to the extent that no overall increases or decreases for any of the rate classes results before application of the RSM credits to the RSM applicable rate classes, although individual customers within rate classes could see bill increases or decreases depending on their usage characteristics. Any actual remaining fuel cost over- or under-recoveries will be known when total 2013 fuel costs are calculated and should be deferred in accordance with Wis. Admin. Code ch. PSC 116 and addressed in a future proceeding.

While the Commission has not yet used the fuel rules in this manner, the Commission's approach in this case is reconcilable with the Commission's rules and the statute authorizing fuel cost adjustments and justified given the unique circumstances of this case. Most importantly, the fuel rules and Wis. Stat. § 196.20(4)(c) clearly leave the ultimate decision of when and how fuel over-collections are returned to utility ratepayers to the discretion of the Commission. Wisconsin Stat. § 196.20(4)(c) notes both that the approval of fuel costs plans for the test year and the reconciliation "shall be determined by the Commission." Wisconsin Admin. Code PSC

[1] *See, e.g.*, *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, docket 6690-UR-120 (December 9, 2011) (PSC REF#: 156916); *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, docket 6690-UR-120 (January 13, 2011) (PSC REF#: 143675).

§ 116.03(3) further authorizes the Commission to condition the approval of next year's fuel cost plan in any manner the "Commission considers appropriate." The Commission considers it appropriate, in this case, to condition the approval of next year's fuel cost plan upon the use of a portion of the 2013 over-collection to offset the test year's revenue requirement deficiency. There is no dispute that this money belongs to the ratepayers of WPSC and that the over-collection is very likely to significantly exceed the revenue deficiency in this case.

While WPSC may attempt to challenge the process by which the Commission determined a portion of the over-collection should be used in this case, the Commission has more than met the requirements of Wisconsin law. An "opportunity for a hearing" has been provided. The parties were provided due notice that the Commission was considering using the 2013 over-collection in this manner. (PSC REF#: 193487.) The parties were afforded an opportunity to provide written responses to the Commission's proposed plan before the Commission made its Final Decision in this proceeding and provided comments. None of the comments challenged the legality of the process. Finally, the Commission notes that the 2013 fuel reconciliation will still proceed next year. WPSC and any interested parties will have a chance to dispute what the final amount of the over- or under-collection is. In the unlikely event that the over-collection is less than the amount used to offset the test-year's revenue deficiency, the Commission grants a deferral for any over- or under-collections so WPSC will have an opportunity to recover should the over-collection be less than the amount used as an offset in this proceeding.

While the use of the 2013 fuel cost over-collection comports with the law, the Commission agrees with CUB's and WIEG's comments that the use of fuel cost over-collections to offset rate increases should not become routine. The preferred methodology for dealing with fuel cost over-collections, except in unique circumstances, is the reconciliation process set forth in the fuel rules. As noted previously, the unique circumstances in this case, including the significant amount of undisputed fuel cost over-collections, were compelling and justified deviation from strict adherence to time periods outlined in the fuel rule reconciliation process.

Commissioner Nowak dissents. Commissioner Nowak would not offset a portion of the 2013 fuel over-collection against the 2014 electric revenue deficiency.

Revenue Requirement

Fuel Costs

The Commission finds that a reasonable 2014 fuel cost plan year level of monitored fuel costs is $374,213,000, which reflects the costs of generation and purchased energy, minus revenue from opportunity sales of energy and capacity. The fuel cost plan year monitored fuel cost divided by the authorized level of native requirements of 13,692,362 MWh results in an average net monitored fuel cost per MWh of $27.33.

It is reasonable to monitor WPSC’s fuel costs, using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code PSC § 116.06(3).

The fuel cost data in Appendix D shall be used for monitoring WPSC’s 2014 fuel costs.

Spot Coal, Natural Gas, and Heating Oil 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 estimate fuel costs by adjusting commodity prices by an average historical ratio of settlement to futures prices. Data for the last six years show that, on average, settlement prices were 19.5 percent lower than the mid-October futures price for that time period. In recent years, this has been a significant cause of fuel over-collections for WPSC. While much of these over-collections must be refunded to ratepayers, WPSC keeps any over-collections within the 2 percent fuel tolerance band, just as it must absorb any fuel cost under-collections within this band. However, comparing the settlement prices to futures prices over different time periods shows significantly different relationships.

Commission staff's adjustment is premised upon the assumption that there is built-in risk premium in the NYMEX futures market. 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 that ensures the futures price will be reliably higher than the settlement price. The Commission is not persuaded that the limited data set relied upon by Commission staff is a reliable prediction of the future. Over the last 20 years, natural gas prices have been cyclical, showing periods of stability, periods of volatility with a steep rise in price, and periods of volatility with steep declines in price. The Commission is not convinced that relatively recent differences between futures prices and spot settlement prices will continue indefinitely into the future.

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 prevailing prices in the markets used by sophisticated parties on all sides of the transaction, remains the most reliable predictor of future spot prices currently available.

The Commission therefore determines that unadjusted NYMEX futures prices should continue to be used to forecast fuel commodity costs not covered by contract in this test year. Commission staff may continue to monitor the relationship between futures prices to settlement prices, but the Commission is not prepared to further evaluate at this time adjustments, modifications or different methodologies that could be used to forecast commodity costs.

The Commission finds that the estimated spot coal, natural gas and heating oil prices based on 2014 NYMEX future prices from October 15, 2013 (coal and heating oil) and November 4, 2013, for natural gas are reasonable.

Fuel Cost Tolerance Band

Wisconsin Admin. Code § PSC 116.06 (3) establishes a 2 percent fuel cost tolerance band "unless the Commission sets a different percentage when approving a fuel cost plan . . . ." WPSC's fuel costs are currently monitored under a 2 percent fuel cost tolerance bandwidth. WPSC requested a 1 percent fuel cost tolerance band for the 2014 test year, citing the increased cost uncertainty and volatility associated with the power supply sources replacing the Dominion purchased power agreement. WPSC also proposed reducing or eliminating the fuel cost tolerance band as a way to satisfy Commission staff's and CUB's concerns about WPSC over-collecting on its fuel costs. Both CUB and WIEG supported the retention of the 2 percent bandwidth as being necessary to provide an incentive to utilities to properly forecast and control fuel costs and mitigate risk to ratepayers.

The Commission will retain the current 2 percent fuel cost tolerance band. The current bandwidth has been working well to incent WPSC and other utilities to carefully forecast and control their fuel costs.

Minimum Rail Tonnage Obligations

Under its current contract with the Union Pacific Railroad (UP), WPSC must ship a certain annual tonnage of coal or it will be subject to minimum tonnage obligation costs. In its filing, WPSC forecasted $8.6 million ($6.7 million on a Wisconsin retail basis) of total rail minimum obligation costs. That amount was based on the utility's forecasted test-year coal-fired generation. Using Commission staff's forecasted increased coal-fired generation results in decreased rail minimum obligation costs. WIEG argued against the inclusion of these costs in the test-year revenue requirement, as these costs are not known and measurable, and that inclusion of these costs increases the likelihood that WPSC will over-collect on its fuel costs. WPSC noted that the Generally Accepted Accounting Principles and the Commission's Uniform System of Accounts require that WPSC accrue for these costs. WPSC also noted that rail minimum tonnage obligation costs have been included in WPSC's rates since 2011, and since then WPSC has consistently tried to find ways to minimize these costs. WPSC argued that since it is required to accrue for the rail minimum tonnage obligations in 2014, it should be allowed to recover these costs in test-year rates, or that, alternatively the Commission could allow WPSC to defer these costs for possible future rate recovery.

The Commission is concerned that some of these costs may not ultimately be incurred and are too uncertain to include in the revenue requirement. However, the Commission recognizes that the costs may be incurred prior to WPSC's next full rate case. The Commission therefore authorizes WPSC to defer its rail minimum tonnage obligation costs under its UP contract, with the requirement that at the time it seeks rate recovery for these costs, it is required to submit a detailed analysis documenting its efforts to eliminate or minimize these costs.

Sales of Electricity to Residential Customers

WPSC forecasted an 18 percent drop in residential lighting usage from 2012 to 2014 due to its forecast of the effect of new federal lighting standards contained in the Energy Independence and Security Act of 2007 (EISA).

Commission staff increased residential sales of electricity by $10.8 million, based on a three-year average of usage per customer and increased customer counts. WIEG proposed an increase of $8.2 million to WPSC's estimate of residential revenues (net of fuel cost).

The Commission determines that Commission staff's adjustment is reasonable. WPSC was unable to provide several key assumptions which would materially affect the impact of EISA on 2014 sales. WPSC has overestimated the likely impact of EISA, and has underestimated sales in recent years. The Commission expects the impact of EISA to be similar to impacts of demand side management programs already included in recent sales trends due to many factors that delay and temper the impact.

Payroll Wage Increases

WPSC's forecasted test-year payroll expense included estimated wage increases in each of the years 2013 and 2014 of 3.45 percent for executive employees and non-union employees, and 3.60 percent for union employees. Commission staff's forecasted test-year payroll expense reflected actual annual wage increases of 2.60 percent for all non-union employees in 2013, estimated wage increases of 1.60 percent for union employees operating without a settled contract in 2013 based on forecasted inflation, and wage increases in 2014 of 1.8 for all employees based on forecasted inflation. Shortly before the hearing date in this proceeding, Union Local 420 ratified a new union contract which results in an additional forecasted test-year expense of $452,000 over the Commission staff forecasted total company payroll expense and concessions in benefits that result in a reduction in a forecasted total company test-year benefits expense of $1,692,000. The Commission finds it reasonable to incorporate the ratified union wage increases into the test-year revenue requirements for union employees' payroll expense and reduce benefits expense associated with the union benefits concessions.

Incentive Compensation

WPSC requested recovery of both its executive and non-executive incentive pay plan costs in its initial filing. Commission staff excluded both incentive plan expenses summing to $8.4 million because WPSC had not demonstrated that these plans provide a direct benefit to ratepayers in excess of the compensation cost. The costs associated with both incentive pay plans were excluded from WPSC's revenue requirements in docket 6690-UR-120 and were not an issue in the most recent settled rate case in docket 6690-UR-121. WPSC's non-executive incentive plan now excludes the net income related metric, and it has eliminated management's discretion to pay no incentive in a given year. The majority of the executive incentive performance measures continue to consist of meeting financial criteria associated with earnings per share and half of the non-executive incentive performance measures are associated with cost management of non-fuel operating and maintenance expenses. WPSC subsequently revised its request to exclude the portion of its executive incentive plan costs associated with financial goals.

The Commission is not persuaded it should change its practice of excluding incentive compensation from revenue requirements of the major investor-owned utilities in Wisconsin. WPSC has not demonstrated that the plans provide substantial ratepayer benefit with enough quantified permanent savings to ratepayers to warrant inclusion of the costs in revenue requirement. With the majority of executive incentive performance measures still tied to meeting earnings per share criteria, and the non-executive incentive performance measures that weigh heavily on measures tied to the shareholders benefit, the Commission finds it is reasonable to exclude all incentive compensation costs from the revenue requirement.

Economic Development Expenses

WPSC's forecasted revenue requirements included an economic development budget of $304,000. Consistent with recent rate case decisions, Commission staff included 50 percent of the forecasted economic development expenses in revenue requirements for costs forecasted to be related to customer assistance and business/load retention. WPSC proposed using dedicated staff to work on attracting new companies to WPSC's service territory and supporting existing business expansion, including working with local and state governmental agencies, local communities, and development corporations to create new business investments and jobs in the regions served. In addition, WPSC anticipates making approximately $120,000 in direct cash contributions to county economic development corporations within WPSC's service territory.

The purpose of all of WPSC's economic development costs is to retain or increase load in WPSC's service territory. WPSC's efforts are consistent with the state's economic development goals and the amount of costs associated with these efforts is modest. Further, all of WPSC's customers will benefit from any success in the form of additional usage over which to spread fixed costs. The Commission finds that inclusion of $304,000 in revenue requirement for economic development expenses as requested by WPSC is reasonable.

Commissioner Callisto dissents.

Deferred Costs from 6690-UR-121 Rate Case Settlement

The Final Decision in docket 6690-UR-121 authorized deferrals of approximately $8.7 million for electric operations and $2.1 million for natural gas operations as part of a settlement which resulted in no change in rates for 2013. These deferrals were to reflect the incremental cost of debt for the electric utility, and the updated pension and benefits costs for electric and natural gas operations.

Commission staff suggested that the Commission may want to conduct an earnings review of 2013 before considering whether it is reasonable to allow recovery of these additional costs in revenue requirement. However, to be consistent with the Final Decision in 6690-UR-121, which found the settlement to be a reasonable outcome, the Commission finds it reasonable to include the deferred costs associated with the settlement agreement in the test-year 2014 revenue requirements. To do otherwise would be inconsistent with that settlement and may provide a disincentive for other utilities to engage in rate case settlement discussions in the future.

Environmental Mitigation Projects Associated with the EPA consent decree

WPSC entered into a consent decree with the EPA on January 4, 2013, that was subsequently approved by the United States District Court for the Eastern District of Wisconsin on March 7, 2013, in which WPSC negotiated a settlement with the EPA for alleged violations of the Clean Air Act arising out of various projects undertaken at WPSC's Pulliam and Weston coal facilities. Part of the consent decree requires WPSC to spend at least $6 million on EMPs over a five-year period. Although not included in its filing, WPSC requested to recover $2.1 million it projects to incur in 2014 for a portion of the minimum $6 million of EMP costs.

Commission staff expressed concerns regarding the rate recovery of EMP costs associated with the consent decree pertaining to the deferral authorization denial, whether the EMPs could be considered as penalties, and whether the EMPs were utility-related and would provide substantial ratepayer benefit.

On April 18, 2013, the Commission denied WPSC's deferral request in docket 6690-GF-132. However, WPSC argued that in denying the deferral request for the Weston and Pulliam units, the Commission cited the relatively small impact on WPSC's return on equity. The prudence and recoverability of the costs were not addressed, and therefore WPSC believed it could continue to record a regulatory asset for future expenses that it planned to include in the 2014 rate case and beyond, with an expectation that it was probable that an amount at least equal to the capitalized costs would be recovered in rates in future rate cases.

WPSC argued that the EMPs should not be viewed as penalties because the consent decree does not identify them as such and that they are intended to remediate the impacts of the alleged non-compliance. WPSC also argued that the consent decree was in the best interest of WPSC and its customers because additional litigation would have been very costly. The Commission agrees that the EPA settlement was prudent and in the best interest of its customers. There is no dispute that the settlement is in the best interests of both WPSC and its customers and was a less costly way to resolve the litigation with the EPA, as compared to the alternatives.

Therefore, the Commission finds it is reasonable to include the impacts of the EMP costs forecasted to be incurred in 2014 in electric revenue requirement.

Commissioner Nowak dissents. Commissioner Nowak would have allowed 75 percent of the EMP costs in revenue requirement and disallowed 25 percent for projects with more limited benefits to ratepayers.

Recovery of the Costs of Meeting the More Stringent Emissions Limits per the Consent Decrees

As part of the conditions of the Consent Decree it entered into for its own plants and the Edgewater 4 plant it owns jointly with WP&L, WPSC is also subject to more stringent sulfur dioxide and nitrogen oxide limitations at the affected plants. Commission staff increased fuel costs by $626,000 ($490,000 Wisconsin retail) to reflect the cost of compliance with these more stringent emission limits at WPSC's own plants, but included no additional dollars for WPSC's share of the incremental costs of compliance with the more stringent emissions limits at Edgewater 4. WPSC proposed to not include any additional costs for compliance with the more stringent limits at Edgewater 4, but to include the actual costs of compliance in its reported monitored fuel costs. Commission staff and CUB suggested to the Commission that the incremental compliance costs could be excluded from the revenue requirement and monitored fuel costs, as these costs could be viewed as *de facto* fines or penalties, or being in lieu of additional fines or penalties.

The Commission is concerned with utilities seeking settlements with the EPA that minimize costs that the Commission has excluded from the revenue requirement at the expense of raising other, recoverable costs. The Commission will continue to evaluate these types of settlements to ensure that they are in the public interest. On the other hand, the Commission is not a party to the negotiations and is hesitant to upset negotiated resolutions that may, on balance, be in the best interest of Wisconsin ratepayers. Disallowing recovery of these costs may act as a disincentive for utilities to pursue such settlements and make such settlements more difficult to achieve in the future. As noted previously, it is undisputed that this settlement is in the best interests of both WPSC and its customers. In addition and unlike some of the costs associated with the EMPs, compliance with the more stringent emission limits directly benefits ratepayers. As a result, the Commission will include these costs in the revenue requirement.

Other Deferrals

As a result of the ratemaking process, and with reasonable regulatory assurance of future cost recovery, utilities sometimes include allowable costs in a period other than the period in which those costs would be charged to expense by an unregulated enterprise in accordance with generally accepted accounting principles. These differences usually relate to the timing of the recognition of a cost. The result of these timing differences is the creation of deferred accounts.

As discussed above, the Commission's policy on deferred accounts is set forth in the Commission's Statement of Position, SOP 94-01. Appendix E is a list of those deferred accounts approved for WPSC, the amortization period, and the amount of Wisconsin jurisdictional 2014 test-year amortization expense. It is appropriate to treat all amortizations as normal test-year expenses by recording the full amounts in the test year.

Electric and Gas Revenue Stability Mechanisms

The electric RSM and the natural gas RSM were initially proposed in a stipulation between WPSC and CUB in the fall of 2008 in docket 6690-UR-119. The Commission accepted the terms of the stipulation but also imposed caps on the amounts that could either be recovered in rates due to an under-collection or returned to customers from an over-collection in any year. The RSMs were applicable only to the residential, small commercial and medium-size commercial classes and were in place for four years until the terms of the stipulation expired at the end of 2012. In the fall of 2012, the Commission accepted a settlement proposal made by WPSC in docket 6690-UR-121 that included provisions that replaced the expiring electric RSM and the natural gas RSM with modified RSMs. The modified RSMs have been in place for 2013. These modified RSMs differed from the original RSMs in several ways. First, the modified RSMs included revenue from monthly customer charges and removed consumption per customer as a factor. Secondly, the modified electric RSM changed the way that the margin per kilowatt-hour (kWh) was determined. The original electric RSM subtracted the average LMP from the kWh energy charge for each class over the course of the year to determine margins from energy sales. The modified electric RSM substituted WPSC's monitored fuel cost per kWh for the LMP in the formula.

In this proceeding, WPSC proposed to continue the electric RSM and the natural gas RSM in their current form indefinitely. WPSC also proposed to eliminate the rate adjustment caps. WPSC argued that the RSMs mitigate risks to the utility that result from differences between sales forecasts and actual sales caused by weather, economic conditions and energy efficiency. WPSC also argued that the RSMs remove any financial incentive that the utility may have to maximize sales.

CUB urged the Commission to discontinue the RSMs. CUB stated it had supported the RSMs when they were initially implemented, but that now WPSC wanted the RSMs to continue while offering nothing to ratepayers in return. Commission staff also encouraged the

Commission to reject WPSC's proposal because the utility had little influence on the energy efficiency decisions made by ratepayers and that WPSC had not shown that it would be financially harmed if the RSMs were discontinued.

WPSC has not offered ratepayers anything in return for the risk reduction that the utility would realize if the RSMs were continued. In addition, because Wisconsin has separated the administration of energy efficiency programs from the utilities through FOE, it is not clear that WPSC can influence ratepayer decisions relating to energy efficiency. The Commission is also persuaded by the unwillingness of CUB and WIEG, representatives for the customer classes who are primarily affected by continuation of the RSM, to continue to embrace the decoupling pilot. For these reasons, the Commission does not find it reasonable to continue the electric RSM and the natural gas RSM as proposed by WPSC.

For test year 2014, applicable electric utility customers are credited with $12,764,000 of RSM-related over-collections of 2012 sales. For test year 2014, applicable natural gas utility customers are charged with $7,877,000 of RSM-related under-collections of 2012 sales. Both of these amounts are reflected in the test-year income statements.

Energy Efficiency

Customer Service Conservation

WPSC's proposed 2014 natural gas and electric customer service conservation (CSC) activities are essentially the same as provided to its customers in the recent past. These activities include providing energy efficiency information and education through field and call center staff, advertising campaigns and bill inserts, newsletters, K-12 Energy Education, and annual memberships and sponsorships. All of these activities have been approved by the Commission in the past.

Since the Commission last approved WPSC's CSC activities, it provided further guidance regarding appropriate CSC activities. In its Order in docket 5-BU-102, dated July 13, 2012, the Commission defined CSC activities as a "those activities and services that a utility provides its customers to: (1) help them understand and control their energy use and bills; (2) create customer awareness of energy efficiency and its value; (3) provide information and assistance related to energy efficiency topics; or (4) encourage and assist customers to take advantage of other services provided by Focus on Energy and federal and state energy programs. Fifty-one percent (51%) of an activity or service must be dedicated to energy efficiency in order to meet the definition of CSC."

Based on this guidance, several of WPSC's proposed CSC activities are inappropriate for inclusion in the conservation escrow budget. WPSC proposed allocating a portion of its labor dollars for the Customer Call Center, Business Solution Center, Residential Billing Team, Agriculture Group, Account Management Group, and Communications Support Group to CSC. While the Commission recognizes that these work groups provide some energy efficiency-related services, the majority of their time is spent on other activities. The Commission determines it is reasonable to remove the labor dollars associated with these activities from the conservation escrow. The Commission also determines that it is not appropriate to fund the J.D. Power study proposed by WPSC through the conservation escrow. Finally, the Commission determines that the public benefits dollars WPSC annually transfers to the Department of Administration as required by 2005 Wisconsin Act 141 should not be funded through the conservation escrow. While some of these funds provide for low-income weatherization, a majority of the funds go to bill payment assistance.

Metrics of Success

WPSC did not propose metrics of success for its CSC activities. 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 WPSC to work with Commission staff to develop metrics of success for the 2014 CSC activities approved by the Commission. It is appropriate that these measures of success be developed by January 31, 2014.

Conservation Budget and Escrow Adjustment

WPSC filed a proposed 2014 conservation budget of $24,217,236, with $17,757,790 allocated to electric operations and $6,459,446 allocated to natural gas operations. Commission staff's analysis of conservation expenses included reviewing the proposed test-year conservation expenditures, forecasting the over-spent balance in the conservation escrow at the beginning of the test year, and reviewing WPSC's forecasted amortization expense associated with previously escrowed conservation expenditures. As a result of this analysis, Commission staff forecasted a $2,684,785 over-spent balance at January 1, 2014, for electric operations and a ($2,553,352) under-spent balance at January 1, 2014, for natural gas operations. Commission staff's forecasted revenue requirement includes the amortization of the estimated over-spent and under-spent balances over the three years beginning in 2014, or $894,928 test-year amortization of the estimated electric over-spent balance and ($851,117) test-year amortization of the estimated natural gas over-spent balance.

The reasonable level of expensed conservation costs recoverable in rates for the 2014 test year is $16,644,714 for electric utility operations and $4,263,100 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $15,750,854, an escrow amortization adjustment of $894,928, and a net adjustment for miscellaneous corrections of ($1,068). The electric escrow adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2013, over three years. The level for natural gas operations consists of the conservation budget of $5,121,489, an escrow amortization adjustment of ($851,117), and a net adjustment for miscellaneous corrections of ($7,272). The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2013, over three years.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to WPSC'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:

	Electric (000's)	Natural Gas (000's)
Operating Revenues		
Sales of Electricity	$966,186	$ ---
Sales of Natural Gas Including Transportation	---	325,406
Other Operating Revenues Including Opportunity Sales	65,704	(6,638)
Other Income - Before Tax	(262)	---
Total Operating Revenues	$1,031,628	$318,768
Operating Expenses		
Fuel and Purchased Power	$464,446	$ ---
Purchased Gas Expense	---	195,119
Other Production Expenses	93,188	4,379
Transmission Expenses	128	754
Distribution Expenses	46,852	22, 372
Customer Accounts Expenses	15,051	9,748
Customer Service & Sales Expenses	24,027	7,383
Administrative & General Expenses	63,606	19,129
Total Operation & Maintenance Expenses	$707,298	$258,884
Depreciation Expense	83,027	17,005
Amortization Expense	16,139	1,964
Taxes Other Than Income Taxes	37,385	4,967
Income Taxes	59,074	10,549
Total Operating Expenses	$902,923	$293,369
Net Operating Income	$128,705	$ 25,399
Adjustments to Net Operating Income	34	---
Adjusted Net Operating Income	$128,739	$ 25,399

Average Net Investment Rate Base

Summary of Average Net Investment Rate Bases

The electric and natural gas net investment rate bases (NIRB) include uncontested deductions for accumulated depreciation. A portion of accumulated depreciation represents accumulated deferred income taxes (ADIT). The Commission finds it reasonable to increase ADIT, and correspondingly decrease NIRB, to reflect amendments to Wisconsin tax law that adopts federal depreciation and amortization, and to increase ADIT, and correspondingly decrease NIRB, to reflect the elimination of a projected deferred tax asset related to a federal NOL carry forward. Due to other adjustments in this proceeding, the Commission does not project a taxable NOL position for 2013.

All uncontested Commission staff adjustments to WPSC's filed average NIRB's are appropriate. Accordingly, the estimated Wisconsin retail electric and natural 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:

	Electric (000's)	Natural Gas (000's)
Utility Plant in Service	$3,010,316	$735,297
Less: Accumulated Reserve for Depreciation	1,601,958	416,410
Net Utility Plant	$1,408,358	$318,887
Add: Natural Gas in Storage	---	23,442
Fuel Inventory	33,687	---
Materials and Supplies	28,239	1,792
Other Investments - net of tax	695	---
Less: Customer Advances	8,273	2,093
Average Net Investment Rate Base	$1,462,706	$342,028

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 8.80 percent for Wisconsin retail electric utility operations and 7.43 percent for Wisconsin retail natural gas utility operations.

Financial Capital Structure and Dividend Restriction

The long-term range for WPSC's common equity ratio, on a financial basis, is 49 to 54 percent common equity. Historically, the capital structure for WPSC has been balanced with equity infusions from and special dividends to Integrys 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 51.0 percent, provided that the amount of the equity infusion will offset new indebtedness and does not result in cash or cash equivalent holdings. This target level is consistent with the 49 to 54 percent range established by the Commission.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. The imputed debt results in additional costs to ratepayers because the utility is required to add sufficient common equity to maintain its target equity level, and the higher return earned on the additional equity increases the weighted cost of capital. In addition, imputing debt for off-balance sheet obligations is not a common practice of other state utility commissions. The Commission is not obligated to adopt the risk assessment of an outside rating agency and will independently examine off-balance sheet obligations, based on its assessment of risk.

To independently examine off-balance sheet debt obligations, it is reasonable to require that WPSC submit detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and Purchased Power Agreements (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 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 documentation when S&P and other major credit rating agencies documentation is not available.

For the test year, the Commission finds it reasonable to impute in aggregate $18,430,000 of debt equivalent. Of this amount, $509,000 is relating to non-purchased power operating leases and $5,888,000 of subsidiary debt related to WPSC's subsidiary, WPS Leasing. The operating lease imputation is based on 100 percent of the present value of the payment streams, while the subsidiary debt is the forecasted average principal outstanding for the test year.

An additional $11,820,000 of imputed debt relates to PPAs and includes approximately $10,349,000 for debt equivalence for contracted capacity payments to Manitoba Hydro and an additional $69,000 for debt equivalence associated with contracted capacity payments to other parties. The imputations are based on a 40 percent risk factor applied to the present value of the payment streams. An additional $1,402,000 of debt equivalence is associated with calculated proxy capacity payment associated with the energy contract minimums and a 25 percent risk factor adjustment. Use of a 25 percent risk factor reflects the expense is recovered through the fuel clause.

Consistent with its treatment in previous dockets, the Commission determined that no debt imputation should be included for wind, parallel generation, and renewable portfolio standard purchased power agreements. The Commission determines that the debt imputation for the wind related land leases shall be based on the lesser of the present value of the payments, assuming continued operation of the wind turbines and the present value of the termination payments if the operation is discontinued. For the test year, one year of lease payments was treated as the proxy termination payment with a present value of $213,000.

Lastly, neither WPSC nor Commission staff included debt imputation associated with obligation categories of advances from associated companies, affiliated capital leases, purchased power capital leases, guarantees, underfunded pension and other post-retirement employee benefit plans, or asset retirement obligations. For each of the above categories, either WPSC does not have any obligations or this Commission has previously determined not to include debt imputations for these categories.

Incorporating the above debt equivalences for off-balance sheet debt obligations and other Commission determinations, WPSC's financial capital structure for the test year will consist of 51.00 percent common equity, 1.88 percent preferred stock, 43.14 percent long-term debt, 3.31 percent short-term debt, and 0.67 percent debt equivalence for off-balance sheet obligations, including subsidiary debt. The 51.00 percent common equity, on a financial basis, is consistent with the common equity target.

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

Generally, under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs if ratepayers are to be protected. The identification of utility needs goes beyond foreseeable needs. WPSC must have flexibility to finance both foreseen and unforeseen capital requirements.

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, WPSC shall not pay, without Commission approval, normal dividends greater than 103 percent of the prior year's common dividend. WPSC shall notify the Commission if any special dividend is contemplated. No special dividend that might cause the common equity, on a financial basis as calculated in this Final Decision, to drop below the projected calendar year average of 51.00 percent or the dollar amount of equity reflected in the test year, is permitted without Commission approval.

Ten-Year Financial Forecast

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

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, in order to arrive at the common equity amount for WPSC's regulatory capital structure, Commission staff deducted WPSC's investment in common equity of the American Transmission Company LLC (ATC), net of deferred income taxes associated with transmission assets transferred to ATC, along with other non-utility items, from booked common equity. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consists of 50.14 percent common equity, 1.94 percent preferred stock, 44.51 percent long-term debt, and 3.41 percent short-term debt.

Short-Term Debt

WPSC's test-year capital structure contains approximately $90 million of short-term debt in the form of commercial paper. A reasonable estimate of WPSC's average cost of short-term commercial paper debt for the test year is 0.40 percent. The forecast is based on the average of commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter. This is a reasonable and objective method of determining WPSC's short-term debt costs.

Long-Term Debt

WPSC's test-year long-term debt includes a financing of $450 million 30-year debt forecasted for December 2013. A reasonable estimate for the cost of the issuance is 4.50 percent. The resulting embedded cost of long-term debt is 4.85 percent for the test year.

Preferred Stock

In its Certificate of Authority and Order, dated October 16, 2012, in docket 6690-SB-134, this Commission granted WPSC the authority to issue $30 million aggregate principal amount of new preferred stock to refinance $30 million of higher cost preferred stock. The Commission finds it reasonable that the refinancing, if it occurs, be handled outside this proceeding on a revenue neutral basis. Consequently, test-year capital structure contains $51,188,200 of preferred stock at its current embedded cost of 6.08 percent.

Return on Common Equity

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

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers, with due considerations to economic and financial conditions along with public policy considerations. If the investors' required return could be measured precisely, setting the authorized return would be straightforward. Because that return cannot be measured precisely, determining the appropriate return on equity is typically one of the most contested issues in a rate proceeding such as this one.

In this proceeding, WPSC's application requested an increase in its current authorized return from 10.30 percent to 10.75 percent. WPSC's financial witness supported a return of 10.75 percent, which was later updated to 10.60 percent. CUB supported a decrease in the authorized return. CUB's witness recommended 9.00 percent if the decoupling program was not approved and 9.50 percent if the Commission determined that it would set the authorized return on the basis of gradualism. Commission staff suggested that the appropriate return on equity be set somewhere in the range from 10.00 percent to 10.20 percent and used 10.20 percent. Commission staff's range was based on the principle of gradualism. The revenue impact for each 10-basis points is approximately $1,500,000 for electric and $300,000 for gas.

Given the above-mentioned considerations, 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 the applicant to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs.

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	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$1,323,663,155	50.14%	10.20%	5.11%
Preferred Stock	51,188,200	1.94%	6.08%	0.12%
Long-Term Debt	1,175,100,000	44.51%	4.85%	2.16%
Short-Term Debt	90,055,133	3.41%	0.40%	0.01%
Total Utility Capital	$2,640,006,488	100.00%		7.40%

The weighted cost of capital of 7.40 percent is reasonable for WPSC for the test year. It generates an economic cost of capital of 10.91 percent and a pre-tax interest coverage ratio of 5.03 times on the regulatory capital structure, and 5.13 times on the test-year financial capital structure.

Rate of Return on Rate Base

The 7.40 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 WPSC's average net investment rate base plus CWIP for the test year is 91.59 percent of capital applicable primarily to utility operations plus deferred investment tax credits. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base.

To allow a test-year current return on the average CWIP balance not accruing AFUDC at 100 percent, an adjustment must be added to the return on net investment rate base. Given WPSC's financing and cash flow requirements in the test year and the forecasted amount of construction activity, the Commission finds it reasonable to allow a current return on 50 percent of CWIP that is not accruing 100 percent AFUDC for the test year.

Consistent with prior Commission decisions, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the DEC premium and to include adjustments for Crane Creek revenue normalization, deferred production tax credits, less depreciation; Fox Energy Center purchased power contract buyout, acquisition adjustment and CSA amortization; the Glenmore Wind Asset retirement; and the deferred tax proration adjustment required in federal tax normalization rules when setting rates based on a forecasted test year, at the authorized adjusted weighted average cost of capital. In addition, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the remaining RSM balances, Columbia and Edgewater precertification and preconstruction deferral balance, the CSAPR deferral, reductions for two electric fuel refunds, and a reduction for the remaining balance of additional natural gas-related FOE payments at the authorized short-term debt rate.

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

	Electric	Natural Gas
Weighted Cost of Capital	7.40%	7.40%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	91.59%	91.59%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	8.08%	8.08%
Adjustment to Return Requirement to Provide Current Return on CWIP, DEC, Crane Creek, Fox Energy Center, Glenmore, and tax proration at the Adjusted Weighted Cost of Capital	0.60%	0.04%
Adjustment to Return Requirement to Provide Current Return on remaining RSM balances, Columbia and Edgewater precertification and preconstruction balances, CSAPR deferral, and reductions for two electric fuel refunds and remaining balance of additional FOE payments at the composite short-term debt rate	0.00%	0.01%
Required Rate of Return on Average Net Investment Rate Base	8.68%	8.13%

Revenue Requirement

On the basis of the findings in this Final Decision, a $12,764,000 decrease in Wisconsin retail electric utility revenues and a $3,996,000 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:

	Electric	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	8.80%	7.43%
Required Return on Average Net Investment Rate Base	8.68%	8.13%
Earnings Deficiency (Excess) as a Percent of Average Net Investment Rate Base	(0.12)%	0.70%
Average Net Investment Rate Base (000's)	$1,462,706	$342,028
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	($1,755)	$2,394
Revenue Deficiency (Excess) to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	($2,929)	$3,996
Adjustment to Include a portion of Estimated 2013 Fuel Refund	($9,835)	---
Net Revenue Deficiency (Excess)	($12,764)	$3,996

Electric COSS and Rates

Electric Cost of Service

WPSC, CUB, WIEG, and Commission staff testified regarding COSS issues and the appropriate allocation methods for allocating the plant and operating expenses that make WPSC's revenue requirement. WPSC and WIEG each prepared a COSS reflecting each party's preferred allocation methods. Commission staff prepared three additional studies based in part on the methods used by staff in prior WPSC rate case proceedings. While CUB did not submit the results of its own COSS model, CUB testified that, based on its preferred allocation methods, it supported the use of Commission staff's "Location" COSS model.

While the parties were unable to arrive at consensus regarding the allocation of various plant and operating expenses, the testimony given in this proceeding provided a robust discussion of the merits of the various COSS methodologies employed. The current Commission practice of considering the results of more than one COSS, as well as other factors, when allocating revenue responsibility is supported by this discussion. The Commission finds that it is reasonable to continue to consider the results of more than one COSS along with other factors, such as bill impacts, when allocating revenue responsibility.

In docket 6690-UR-120, WIEG proposed distinguishing between single-phase and three-phase distribution assets. The Commission ordered staff to work with WPSC, intervenors in that case, and other major Wisconsin investor-owned utilities to explore this issue further. Based on those discussions, WPSC modified its primary distribution allocation method. WPSC used the revised method in its 2013 test-year rate case filing in docket 6690-UR-121. However, that proceeding settled before Commission staff and intervenors filed any witness testimony. WPSC carried the revised method over to the COSS it prepared in this proceeding. This proceeding is the first opportunity Commission staff and intervenors have had to address the modification.

In its discussion of COSS methodologies in this proceeding, WIEG again introduced a method for allocating three-phase primary distribution costs and suggested that WPSC be ordered to use WIEG's allocation method, expressing dissatisfaction with the precision of the modified primary-voltage distribution system allocation method used by WPSC. WIEG's proposal categorizes 50 percent of WPSC's primary distribution system as single-phase and 50 percent of it as three-phase, with the single-phase portion allocated 100 percent to secondary customers and the three-phase portion allocated to primary and secondary customers.

WPSC and Commission staff agreed in principle with aspects of WIEG's proposed primary-voltage allocation refinement, but did not agree to the adoption of WIEG's approach. WPSC agreed to conduct a more thorough examination of this issue and to include additional information and any appropriate adjustments to its electric COSS in its next general rate case filing. Commission staff expressed concerns regarding the method by which WIEG arrived at its proposed single-phase/three-phase allocation of 50/50. Commission staff also expressed concern that, in focusing on the extent to which the single-phase primary distribution system does or does not provide system benefits to primary voltage customers, WIEG's analysis fails to consider whether there are portions of the three-phase primary voltage system that provide more benefits to primary customers than secondary voltage customers. Commission staff suggested that if the Commission believes this issue requires further study, WPSC should be directed to conduct additional analysis of this issue with results presented prior to the filing of the utility's next base rate case. WPSC opposed Commission staff's suggestions for the utility to address this issue more aggressively, citing its commitment to further study and inadequate time before the scheduled timing of the utility's next rate filing.

The Commission continues to acknowledge that COSS methods that allow for a more granular recognition of single-phase and three-phase primary-voltage distribution circuit costs may be of some value when assigning revenue responsibility. The Commission finds merit in WIEG's argument that a more granular allocation of primary-voltage distribution system costs than that used by WPSC in this proceeding may be possible. However, the Commission is sufficiently persuaded by the concerns raised by Commission staff to conclude that, while representing a good first step, WIEG's analysis of primary-voltage distribution system costs and cost causation is insufficient, and as such WIEG's proposed primary-voltage distribution allocation method does not merit adoption at this time. Given the information presented in the record, and recognizing the limits of the way WPSC currently tracks distribution asset costs, the Commission finds the method used by WPSC in this proceeding to allocate primary-voltage distribution circuit costs to be reasonable, and finds it unnecessary at this time to order WPSC to perform additional study. If WIEG wishes to continue to pursue this issue, the Commission encourages WIEG to work with WPSC and other interested parties to perform additional analysis in order to remedy the defects identified in this proceeding. Specifically, the Commission would like the interested parties to work with WPSC to determine what portion of the three-phase system was caused to be built by secondary customers, and whether and what amount primary customers benefit from the single-phase system.

Electric Revenue Allocation

WPSC proposed an electric revenue allocation that is generally above average for the residential classes and the industrial class, below average for the small commercial, lighting, and miscellaneous classes, and around the average for the medium commercial classes. Commission staff proposed an alternative electric revenue allocation that is around the average for the residential classes, below average for the small commercial, lighting and miscellaneous classes, and above average for the industrial class. CUB proposed an electric revenue allocation that is below average for the residential, small commercial, lighting, and miscellaneous classes, and above average for the medium commercial and industrial classes.

The overall electric revenue decrease in this case includes credits associated with an RSM refund along with other costs that are higher. The credits that were proposed must be applied to the RSM rate classes only. These rate classes include the residential, small commercial, medium commercial, and lighting customers that are all of the rate classes subject to WPSC’s decoupling mechanism. For the reasons previously noted, the Commission determined that the overall increase should be offset by fuel credits from an estimated 2013 fuel over-collection.

The Commission generally uses the electric COSS and other information including customer bill impacts as a guide in determining revenue allocation and setting rates. The Commission determined that a change in base rates should mirror the allocation of the fuel cost reduction, in this case, so that the overall changes in electric revenue are zero, except for the application of the RSM credits to the RSM rate classes. This results in little or no change in revenue from the non-RSM rate classes. The electric revenue allocation, along with the electric rate design described below and shown in Appendix B for all of WPSC's electric rate classes, is reasonable and appropriately reflects the Commission's consideration of all of these factors.

Electric Rate Design

WPSC initially proposed significant increases in the levels of the customer charges and demand charges with lesser increases for the energy charges to recover its initially proposed 7.36 percent increase. WPSC also proposed an alternative with the same customer charges and demand charges and decreases for the energy charges to recover the Commission staff proposed 0.96 percent increase. WPSC's proposal included the elimination of separate rural rate classes and moving the three-phase residential customers to the commercial rate classes. WIEG supported WPSC's proposed changes in demand and energy charges for the Cp rate class.

Commission staff proposed changes in customer charges and demand charges, along with increases in energy charges, that produce lesser bill impacts for most customers. Commission staff agreed with WPSC's proposal to eliminate the separate rural rate classes, but disagreed on the proposal to move the three-phase residential customers to the commercial classes.

CUB proposed electric rates for the residential and small commercial customers that included different alternatives for changing the customer charges, depending on whether the RSM mechanism is retained or eliminated by the Commission. CUB proposed either maintaining the customer charges or increases to the level of those rates prior to the Commission decision that implemented the RSM experiment. CUB's electric rate proposal also included increases in the energy charges for the residential and small commercial customers to recover the lower revenue allocation that CUB supports for these classes.

The Commission determines that WPSC's electric rate design, as adjusted for the final revenue requirement and the revenue allocation summarized above, is reasonable. This includes significant increases in the levels of the customer charges and demand charges along with decreases for the energy charges. All of the electric rates are shown in Appendix B.

Commissioner Callisto dissents on the increase in monthly customer charges and on the acceptance of WPSC's proposed changes in demand/energy charges.

Commissioner Nowak dissents on the acceptance of WPSC's proposal to move three-phase residential customers to the commercial rate schedules.

Interruptible Credits

WIEG proposed to increase the credits for interruptible service. WIEG argued that the interruptible credits had not been increased for some time even though firm demand charges had been increased and that this had resulted in an increase in the differential between the firm demand charge and the interruptible demand charge. WPSC's rate design maintained the credits at their current amounts and opposed increasing the interruptible credits. WPSC argued that interruptible customers need only make a short-term commitment to take interruptible service and that the current value of short-term capacity was very low. Commission staff's proposed rate design also maintained the interruptible credits at the current amounts.

The Commission finds that it is reasonable to maintain the interruptible credits at the current amounts.

Real Time Market Pricing Adder

WPSC's Real Time Market Pricing rate schedule includes a $10 per MWh adder to the LMP-based rate. WIEG proposed to decrease the adder on the basis that conditions had changed since the adder was initially designed and that such adders are lower in other jurisdictions. WPSC argued on the basis that the adder is designed to recover the fixed costs of serving customers that take service under this rate schedule and opposed reducing the adder.

It is reasonable to maintain the $10 per MWh rate at this time because WIEG did not make convincing arguments that support its position. The Commission is not persuaded by WIEG's comparison of MWh adders in other jurisdictions. While each of the rates WIEG compares to the WPSC adder may have a lower adder than WPSC, it is not clear that those rates are not making up for the lower adder with other charges. On the other hand, the WPSC adder has not been revisited since its inception. As a result, it is reasonable to require WPSC to work with WIEG and other appropriate stakeholders to evaluate the adder. The results of this evaluation shall be submitted to the Commission in WPSC's next full rate case or rate case reopener.

Electric Tariff Language Changes

WPSC's proposed various language changes to its lighting, electric extension rule, electric service rules, and parallel generation (Pg) tariffs. There were no objections to these changes, except the Pg-2 and Pg-4 tariff changes. The Commission approves the miscellaneous tariff language changes proposed by WPSC that involve issues other than the Pg-2 and Pg-4 rates. The changes contained in Ex.-WPSC-Beyer-1, Ex.-WPSC-Laursen-1 and Ex.-WPSC-Laursen-4 are reasonable.

Customer-Owned Distributed Generation

WPSC proposed a transition schedule for Pg-4 Net Energy Billing customers grandfathered under the general terms of the Pg-4 tariff in effect prior to January 1, 2011. Under WPSC's proposal, affected Pg-4 customers would continue to receive the grandfathered credit treatment until December 31, 2021, at which point those customers would be transitioned to the terms of the Pg-4 tariff in effect at the time. Commission staff indicated that it supports WPSC's proposed transition schedule. RENEW Wisconsin (RENEW) did not comment on WPSC's proposal.

The Commission finds WPSC's proposed transition schedule for grandfathered Pg-4 customers to be reasonable as it provides an acceptable compromise between the utility's desire to set a date-certain sunset timeline, while at the same time allowing for a reasonable payback period for customers who had installed their generation system based on the economics of a retail rate credit.

RENEW proposed that WPSC's Pg-4 Net Energy Billing tariff be modified to allow Pg-4 customers to net their generation against their consumption on an annual basis to align the Pg-4 tariff with the net energy billing tariffs offered by other Wisconsin investor-owned utilities. RENEW suggested the net energy billing tariffs of Madison Gas and Electric Company (MGE), Northern States Power Company–Wisconsin (NSPW), and Wisconsin Electric Power Company

(WEPCO) as possible models for the implementation of an annual netting structure for WPSC's Pg-4 service. WPSC objected to RENEW's proposal based on its cost of service analysis. WPSC argued that allowing customers to net on an annual basis would amount to a subsidy by customers who do not own generation and would compensate customers owning generation at a rate that is multiple times the average LMP. RENEW objected to WPSC's conclusions, arguing that the proposed change would have *de minimis* impact on WPSC revenues, and that WPSC's argument relies on unsupported and conclusory assertions that lack any evidentiary support in the record.

The Commission recognizes that distributed generation buyback rates are currently a heavily contested issue, not only in Wisconsin, but around the country. The Commission finds merit in the concerns raised by WPSC regarding possible fixed cost recovery issues associated with net metering, and possible cross-subsidization by non-participating customers. The Commission has every reason to believe that interest in customer-owned distributed generation will continue to increase as the cost of such generating systems become more cost competitive with retail electric service. As such, the focus should be on getting the right policies in place before this becomes a more significant cost issue.

Given the issues raised, the identified uncertainties, and the potential for unreasonable cross-subsidies, the Commission finds that there is insufficient evidentiary support in the record to support modifying the netting structure of WPSC. Therefore, the Commission finds it reasonable to retain the existing monthly netting structure for WPSC's Pg-4 Net Energy Billing Service.

Commission Callisto dissents and would have directed WPSC to adopt an annual netting structure.

WPSC filed a proposal to roll back the capacity limit of its Pg-4 Net Energy Billing tariff from the 100 kW level authorized by the Commission in WPSC's last full rate case, to 20 kW, citing concerns over reduced energy sales. WSPC also proposed to limit Pg-4 customer generation so that the installed capacity does not exceed what is necessary to serve a customer's expected load. WPSC argued that allowing customer-owned generation with a capacity greater than 20 kW to take advantage of the Pg-4 tariff would impair WPSC's ability to collect its fixed distribution, transmission, and generation system costs that are currently included in its variable energy rates, and would ultimately require customers that do not own generation to subsidize those that do. RENEW objected to WPSC's proposal, suggesting that WPSC had not provided sufficient evidence to support a restriction in the availability of the Pg-4 tariff.

As previously noted, given the fixed-cost recovery issues raised by the utility, the identified uncertainties, and the potential for unreasonable cross-subsidies, the Commission believes that a conservative approach is warranted with respect to the Pg-4 tariff. Therefore, the Commission finds it reasonable to reduce the capacity limit for WPSC's Pg-4 Net Energy Billing service from 100 kW to 20 kW, and to limit Pg-4 customer generation so that the installed capacity does not exceed what is necessary to serve a customer's expected load at the same location. Lowering the capacity limit of the Pg-4 tariff will limit the risk of possible cross-subsidization by non-participating customers.

Commissioner Callisto dissents and would have retained the 100 kW capacity limit.

Current Pg-4 customers with installed capacity greater than 20 kW but less than or equal to 100 kW whose generating facilities were installed after January 13, 2011, may continue to take service under the Pg-4 tariff, provided they do not increase the generation capacity enrolled under the Pg-4 tariff at that location.

The Commission recognizes that there may be customer-owned distributed generation projects currently underway that fall within the 20 kW to 100 kW capacity range, and for which customers may be seeking to take service under the terms of the Pg-4 tariff. Additionally, the Commission is aware that a number of applicants for FOE grants may be affected by the authorized change to the Pg-4 availability criteria. The Commission therefore finds it reasonable for customers with signed applications for generation capacity greater than 20 kW but less than or equal to 100 kW that are submitted to WPSC prior to January 1, 2014, and who, to the satisfaction of WPSC, have made material financial investments in the project, to take service under the Pg-4 tariff. The Commission also find that it is reasonable for customers who submitted an application prior to January 1, 2014, for FOE grants for projects with generation capacity greater than 20 kW but less than or equal to 100 kW to take service under the Pg-4 tariff if the grant is awarded, provided that FOE grant recipients do not increase the generation capacity beyond what was submitted in the grant application.

WPSC proposed to restrict the availability of its Pg-4 Net Energy Billing tariff to exclude demand-metered customers, arguing that the Pg-4 tariff is intended for small customers who are on energy-only rate schedules. WPSC also proposed excluding customers taking service under a Response Rewards critical-peak pricing tariff from the availability criteria for Pg-4, citing administrative burden. RENEW and Commission staff objected to WPSC's proposal. RENEW and Commission staff argue that WPSC did not provide sufficient evidence in support of either of these restrictions in the availability of the Pg-4 tariff and that WPSC's proposal is inconsistent with the cost of service. Commission staff testified that WPSC has indicated that the billing system migration project currently underway at WPSC would eliminate the administrative burden WPSC states is associated with billing response rewards customers under the Pg-4 tariff. WPSC later agreed to withdraw its proposal to limit net metering to the energy-only customers, provided that the Commission agree to return the generated capacity limit to 20 kW and that it exclude response rewards customers.

The Commission finds that WPSC has not provided sufficient evidence to exclude demand-metered customers from taking service under the Pg-4 tariff. Furthermore, the Commission finds that the administrative burden and associated costs that WPSC cites as reason to exclude response rewards customers to be *de minimis* as there is currently only one response rewards customer under the Pg-4 tariff. Moreover, by WPSC's own admission, the administrative burden associated with response rewards customers will be eliminated by the billing system migration project currently underway at WPSC. The Commission finds it reasonable to allow demand-metered customers and response rewards customers to take service under the Pg-4 tariff.

Commissioner Nowak dissents and would have allowed demand-metered customers, but not response rewards customers, to take service under the Pg-4 tariff.

WPSC's Pg-4 tariff currently pays a flat buyback rate for net excess generation under Pg-4. This rate is equal to a weighted average of WPSC's Pg-2A parallel generation on- and off-peak rates. RENEW recommended that the credit rate for net excess Pg-4 generation be modified to reflect “full avoided cost.” RENEW argued that since solar photovoltaic (PV) constitutes the bulk of generation enrolled under the Pg-4, and since solar PV generates primarily, if not exclusively, during peak periods, the use of a single flat rate is unreasonable, and that the energy price component of the avoided cost calculation should only be based on average LMP during the period of 9:00 a.m.-5:00 p.m. RENEW also proposed that the Pg-4 rate include WPSC’s avoided cost of transmission, as was ordered in WEPCO’s most recent rate case, as well as a capacity credit. WPSC opposed RENEW’s proposals arguing that paying more as an “incentive” would constitute a subsidy to these customers who are already avoiding paying fixed costs of service through net metering.

The Commission finds it reasonable to allow WPSC to continue to credit Pg-4 customers for net excess generation at a rate equal to a weighted average of WPSC’s Pg-2A parallel generation on- and off-peak rates. Consistent with the net energy billing tariff authorized for WEPCO in docket 5-UR-106, the Commission finds it reasonable to also credit Pg-4 customers for the WPSC’s avoided cost of transmission.

Commissioner Callisto dissents.

RENEW requested that the Pg-4 tariff be modified to include language stating that the “Customer shall retain all renewable credits and other attributes associated with the energy provided to WPSC pursuant to this tariff.” The intent of RENEW’s intent is to harmonize, with respect to renewable energy credits, the language of WPSC’s Pg-4 tariff with the authorized net energy billing tariffs of MGE and NSPW. RENEW’s proposed change was not contested by any parties. As Pg-4 customers are credited at an avoided cost based rate that does not reflect the value of renewable energy credits or other renewable attributes, the Commission finds RENEW's proposal to be reasonable.

WPSC proposes that the Pg-2 Parallel Generation customer charge be increased from the current $10 per month to $20 per month, arguing that such an increase is supported by WPSC's COSS. Commission staff questioned whether WPSC's COSS overstated the costs of parallel generation customers. Based on the COSS evidence in the record, the Commission finds it reasonable to set the Pg-2 customer charge equal to $20.

Commissioner Callisto dissents.

In docket 6690-UR-120, the Commission authorized Pg-2A and Pg-2B parallel generation tariffs for WPSC, which stated:

> "Should the Midwest Independent Transmission System Operator (MISO) implement a capacity market, a capacity credit shall be implemented reflecting the MISO capacity market methodology. Once the MISO capacity market is operational, Customers with Interruptible Service will not receive any additional capacity charge credit."

WPSC proposed to implement an on-peak per-kWh capacity credit for the Pg-2A and Pg-2B parallel generation tariffs based on the Midcontinent Independent System Operator, Inc., capacity auction clearing price in order to comply with the terms of those tariffs. WPSC proposed a capacity credit for the test year of $0.00010 per kWh. Commission staff did not object to WPSC's proposed credit. However, given that this is a relatively new approach, and considering the fact that other utilities will soon be filing modifications to their parallel-generation tariffs in compliance with similar capacity credit language in their respective tariffs, Commission staff suggested that the Commission direct that a review of market-based distributed generation buyback rates be conducted in a future rate case. The Commission finds WPSC's proposed capacity credit of $0.00010 per kWh for the 2014 test year to be reasonable.

A review of market-based distributed generation buyback rates shall be conducted in WPSC's next general rate case.

RENEW asked that the Commission investigate and quantify the benefits that solar energy customer-generators in WPSC territory provide to their utility and therefore to non-net metered WPSC customers. Commission staff suggested that the Commission may wish to direct that a more in-depth analysis of the costs and benefits of customer-owned distributed generation be performed, with the results of such an analysis submitted in a future base rate case.

At this time, the Commission believes that its recent practice of addressing distributed generation in utility rate case proceedings is reasonable. The Commission does not find it necessary to open an investigation into distributed generation issues at this time and will continue to address distributed generation issues on a case-by-case basis in individual rate case proceedings.

Commissioner Callisto dissents and would have opened a generic proceeding to investigate on a statewide basis distributed generation issues.

Natural Gas COSS, Rates, and Rules

Natural Gas COSS

WPSC and Commission staff prepared three COSS, which utilize different methods to allocate the costs of providing natural gas distribution service to the customer classes. The allocation method of the greatest individual importance is the method used to allocate costs related to distribution mains, which comprise the majority of distribution system costs. WPSC's COSS allocates main-related costs to the customer classes based on customer number and peak demand. Commission staff's COSS A allocates these costs based on customer number, average usage and peak demand. Commission staff's COSS B does not allocate any portion of main-related costs based on customer number, utilizing average usage and peak demand to apportion these costs.

The participants expressed differing opinions about the reasonableness of the methods used to allocate costs. WIEG faulted all three studies because they failed to allocate transmission and distribution main costs based on coincidental daily peak demands and recommended that the Commission adopt the overall percentage rate increase for all customer service rate classes. There was little or no information to suggest what the COSS results would be for a coincidental daily peak demand allocation of transmission and distribution mains. In future rate case proceedings, the Commission encourages WPSC to examine an allocation on the daily peak demand of its service rate classes, but this examination should not be to the exclusion of the other COSS that provide a range of results for the Commission to consider. The Commission has not endorsed a particular natural gas COSS methodology in the past and has relied on the results of all of the COSS to provide a range of reasonableness for revenue allocation and rate design. This continues to be an appropriate policy.

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized in Appendix C of this Final Decision will provide for an 8.13 percent rate of return on the average gas net investment rate base. This represents an increase of 3.07 percent in margin rates and a 1.23 percent in total natural gas sales revenues. Margin rates exclude natural gas costs.

Authorized rates as set forth in Appendix C are based on the cost of providing natural gas service to the various service rate classes and other rate setting goals. A summary of the revenue rate impacts on a service rate class basis is shown in Appendix C.

The authorized rates are based on two rate determinations: the cost of providing natural gas service during the test year (base rates) and the cost of recovering the annual amortization of the regulatory asset associated with the 2012 under-recovery of revenues from the natural gas RSM service rate classes. The cost of providing natural gas service during the test year would represent a decrease in rates of $3,881,000 or an overall decrease in margin rates of 2.98 percent. The cost of recovering the annual amortization of the regulatory asset associated with the 2012 under-recovery of revenues from the natural gas RSM service rate classes represents an increase in rates of $7,877,000, or an overall increase in rates to the natural gas RSM service rates of 7.37 percent. The natural gas RSM service rates are set to expire on December 31, 2014.

As shown in Appendix C, the authorized natural gas rates result in a range of increases and decreases in the charges to the various service rate classes. The largest increase is the increase in the rates for Coal Displacement Gas Transportation Service (CDGT) service. The overall increase to the CDGT service class is 35.15 percent. Yet, this rate represents a considerable discount from similar large-volume gas customers. This rate was never intended to be a long-term discounted rate for service. The rate for this service includes conditional provisions. One such provision states: “The customer must be unable to obtain natural gas under any other schedule of WPSC at a price competitive with the customer's existing coal utilization facilities.” To provide for historical continuity in rates, the Commission finds it reasonable to authorize service rates that move in the direction of the natural gas COSS results, with intent to make further adjustments in that direction in subsequent rate proceedings.

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.

Some typical natural gas bills for residential service were computed to compare existing rates (with and without the 2013 natural gas RSM credit) with authorized rates, including the cost of natural gas and the 2014 natural gas RSM charge. Such comparison is set forth in Appendix C. These rates are reasonable and just.

Residential Monthly Service Charge Rates

As previously stated, some typical natural gas bills for residential service were computed to compare existing rates with new rates including the cost of natural gas, and are shown in Appendix C. Authorized residential rates will provide a greater percentage increase to small-volume residential users when compared to other residential users. This greater increase results because the fixed monthly residential service charge was increased from $7.00 to $10.25 as set forth in Appendix C.

Authorized general service rates will provide a greater percentage increase to the small-volume natural gas RSM service rate customers than for larger-volume users within the same service classes. This is the result of returning to the higher fixed daily distribution service charges that were previously authorized prior to the natural gas RSM rates. The authorized fixed charges for residential customers and the smallest volume commercial customers are designed to recover customer costs, including meter reading, billing and collecting expenses, and the depreciation and return associated with meters and service laterals. WPSC incurs these costs regardless of the volume of natural gas used by its customers, so it is more appropriate to recover such costs through fixed service charges than through volumetric charges. Furthermore, returning to the higher fixed service charges is reasonable because natural gas RSM revenue differences will no longer be recognized.

Proposed Gas Tariff Changes

WPSC proposed revisions to its main and service extension rules, minimum payment option rules, and late payment provisions. The Commission finds the proposed revisions to be reasonable. The revisions are set forth in Appendix C.

Commission staff proposed a PGAC that will revise WPSC's periodic reconciliations to periods similar to the provisions of other state gas utilities, and the change will allow WPSC to file the monthly PGAC with the Commission's online PGAC system. It is reasonable to approve the PGAC tariff as shown in Appendix C.

Penalties for Unauthorized Use of Gas During Low-Flow Constraint Periods

WPSC declared a system-wide, low-flow constraint from March 16, 2012, to March 31, 2012. WPSC assessed a total of $166,422 in penalties and approximately three times the normal level of charges for daily imbalances during this low-flow constraint period. An agreement to modify the imbalance charges for high- and low-flow constraints was made in a collaborative effort by WPSC, Constellation NewEnergy-Gas Division, LLC, Integrys, and Commission staff. However, the parties were unable to reach an agreement on the levels of penalties for the unauthorized use of gas during a low-flow constraint period.

WPSC proposed limiting the applicability of penalties during a WPSC declared low-flow constraint period to when WPSC incurs interstate pipeline penalty charges and/or cycling fees. Integrys believed WPSC's proposal was a step in the right direction; however Integrys believed that a $20.00 per dekatherm penalty from the utility to the marketers and their customers is unreasonable given that the interstate penalty to WPSC could be $0.20 per dekatherm. Integrys recommended that penalties imposed by WPSC be limited to the total amount of penalty charges and/or cycling fees imposed by the interstate pipeline. The Commission finds that it is reasonable to limit the applicability of penalties to when WPSC incurs penalties, and it is reasonable to assess penalties at amounts greater than amounts incurred in order to deter unauthorized use of gas during low-flow constraints. The revised low-flow constraint penalties are set forth in Appendix C.

Commission Callisto dissents.

Effective Date

The Commission finds it reasonable for the authorized electric and natural gas rate increases and all tariff provisions that restrict the terms of service to take effect January 1, 2014, provided that these rates and tariff provisions are filed with the Commission and placed in all offices and pay stations of the utility 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, it is reasonable to require that they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

The Commission finds it reasonable for the authorized electric and natural gas rate decreases and all tariff provisions that do not restrict the terms of service to take effect January 1, 2014. It is also reasonable to require that the utility 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.

Order

1. This Final Decision takes 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 take effect on the date they are filed with the Commission and placed in all offices and pay stations.

3. WPSC 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 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. WPSC 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, WPSC shall revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendices B and C 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. WPSC shall prepare bill messages that properly identify the rates authorized in this Final Decision. WPSC shall provide the messages to customers no later than the first billing containing the rates authorized in this Final Decision, and shall file copies of these bill messages with the Commission before it provides the messages to customers.

7. WPSC shall file tariffs consistent with this Final Decision.

8. The Commission's approval of WPSC's 2014 fuel cost plan is conditioned upon the application of the 2013 fuel cost over-collections to offset the 2014 electric rate increase. WPSC shall be allowed to defer any over- or under-collection of 2013 fuel costs used to offset the 2014 electric rate increase.

9. The electric fuel costs in Appendix D shall be used for monitoring WPSC's 2014 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

10. All 2014 fuel costs shall be monitored using a plus or minus 2 percent tolerance band.

11. WPSC shall be allowed to recover any incremental emissions compliance costs associated with the consent decrees that may be incurred during 2014 and to include those costs in reported monitored fuel costs.

12. WPSC shall defer any minimum tonnage obligation costs incurred during 2014 for possible future rate recovery. WPSC shall submit a detailed analysis documenting its efforts to eliminate or minimize these costs when it seeks rate recovery for these costs.

13. WPSC shall submit a ten-year financial forecast in its next rate case.

14. WPSC shall not pay, without Commission approval, normal dividends greater than 103 percent of the prior year's common dividend. WPSC shall notify the Commission if

any special dividend is contemplated. No special dividend that might cause the common equity, on a financial basis, to drop below the projected calendar year average of 51.00 percent or the dollar amount of equity reflected in the test year is permitted without Commission approval.

15. WPSC 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 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, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

16. WPSC shall record annual conservation accrual amounts of $16,644,714 for electric utility operations and $4,263,100 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $15,750,854, an escrow amortization adjustment of $894,928, and a net adjustment for miscellaneous corrections of ($1,068). The electric escrow adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2013, over three years. The level for natural gas operations consists of the conservation budget of $5,121,489, an escrow amortization adjustment of ($851,117), and a net adjustment for miscellaneous corrections of ($7,272). The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31,

2013, over three years. WPSC shall continue to record these amounts until the Commission authorizes new conservation accrual amounts.

17. WPSC shall work with Commission staff to develop metrics of success for the 2014 customer service conservation activities approved by the Commission. WPSC shall submit its customer service conservation measures of success to the Commission by January 31, 2014.

18. WPSC shall work with WIEG and other appropriate stakeholders to evaluate the energy adder in the Real Time Market Pricing rate schedule. WPSC shall submit this evaluation in its next full rate case or rate case reopener.

19. WPSC shall conduct an in depth review of market-based buyback rates in its next base rate case to determine whether the rates are functioning appropriately.

20. Jurisdiction is retained.

Concurring and Dissenting Opinions

Commissioner Nowak dissents on certain issues, concurs with the resulting Final Decision and writes separately (attached).

Commission Callisto dissents on certain issues, concurs with the resulting Final Decision and writes separately (attached).

Dated at Madison, Wisconsin, this 18th day of December, 2013.

By the Commission:

Sandra J. Paske
Secretary to the Commission

SJP:CCS:cmk:DL: 00890389
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.[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: March 27, 2013

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

Docket 6690-UR-122

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-122

SERVICE LIST
(September 30, 2013)

WISCONSIN PUBLIC SERVICE CORPORATION
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CLEAN WISCONSIN
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(Email: knekola@cleanwisconsin.org; ewheeler@cleanwisconsin.org)

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

Docket 6690-UR-122

INTEGRYS ENERGY SERVICES, INC.
Melissa Lauderdale
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WAUSAU PAPER CORPORATION
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WISCONSIN PAPER COUNCIL
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WISCONSIN INDUSTRIAL ENERGY GROUP
Steven A. Heinzen
Godfrey & Kahn, S.C.
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(Email: sheinzen@gklaw.com; tstuart@wieg.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.

Justin Chasco
Christine Swailes
Candice Spanjar
Public Service Commission of Wisconsin
610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854
(Chasco Phone: 608-266-3708)
(Swailes Phone: 608-266-8776)
(Spanjar Phone: 608-267-9537)
(Email: Justin.Chasco@wisconsin.gov; Candice.Spanjar@wisconsin.gov; Chris.Swailes@wisconsin.gov)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC REVENUE BY RATE CLASS

Rate Classes	Rate Schedule	Present Revenue	Authorized Revenue	Revenue Change	Percent Change
Residential Classes					
Residential Urban	Rg-1	$222,406,154	$220,138,795	($2,267,359)	-1.0%
Residential Rural	Rg-2	119,778,541	116,743,463	(3,035,077)	-2.5%
Urban Res. Optional 2-part TOU	Rg-3-OTOU	7,169,457	7,102,691	(66,766)	-0.9%
Rural Res. Optional 2-part TOU	Rg-4-OTOU	10,124,539	9,875,990	(248,549)	-2.5%
Urban Res. Optional 3-part TOU	Rg-5-OTOU	3,153,491	3,101,450	(52,041)	-1.7%
Rural Res. Optional 3-part TOU	Rg-6-OTOU	324,941	320,023	(4,918)	-1.5%
		$362,957,123	**$357,282,413**	**($5,674,710)**	-1.6%
Small Commercial Classes					
Small C&I - Urban (<50 KW)	Cg-1	$77,782,096	$76,646,945	($1,135,151)	-1.5%
Small C&I - Rural (<50 KW)	Cg-2	34,491,556	33,816,881	(674,675)	-2.0%
Urban Small C&I Optional TOU	Cg-3-OTOU	5,931,635	5,848,820	(82,815)	-1.4%
Rural Small C&I Optional TOU	Cg-4-OTOU	4,064,635	3,960,095	(104,540)	-2.6%
		$122,269,921	**$120,272,741**	**($1,997,181)**	-1.6%
Misc Rate Classes					
Automatic Transfer Switch	ATS-1	51,612	$51,612	$0	0.0%
Parallel Generation	Pg	6,332	11,548	5,216	82.4%
Naturewise	NAT-R	283,594	283,594	0	0.0%
		$341,538	**$346,754**	**$5,216**	1.5%
Lighting Rate Classes					
Lighting Service	LS-1	$13,361,378	$13,360,656	($722)	0.0%
Municipal Ornamental Street Lighting	Ms-31	9,655	9,655	0	0.0%
		$13,371,033	**$13,370,311**	**($721)**	-0.01%
Small Customer Classes (Residential, Small Comm., Misc. & Lighting)		**$498,939,614**	**$491,272,218**	($7,667,396)	**-1.5%**
Medium Commercial & Industrial					
Small C&I - Rural (50 < KW> 100)	Cg-5	$36,712,375	$36,013,064	($699,310)	-1.9%
Cg TOU 100-1000 kW	Cg-20-TOU	206,663,689	202,262,413	(4,401,276)	-2.1%
		$243,376,064	**$238,275,477**	**($5,100,587)**	-2.1%
Large Commercial & Industrial					
Cp Class	Cp	$223,575,465	$223,578,679	$3,213	0.00%
		$223,575,465	**$223,578,679**	**$3,213**	**0.00%**
Total Revenue		**$965,891,144**	**$953,126,374**	**($12,764,770)**	**-1.32%**

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions		Present Rates	Authorized Rates
Rg-1 RESIDENTIAL - Urban			
Equivalent Monthly Customer Charge:	Single-phase	$5.70	$10.40
	Three-phase	$9.70	$17.70
Daily Customer Charge:	Single-phase	$0.1874	$0.3419
	Three-phase	$0.3189	$0.5819
Energy Charge (per kWh)		$0.12061	$0.11143
Rg-2 RESIDENTIAL - Rural (Closed and Customers moved to Rg-1)			
Equivalent Monthly Customer Charge:	Single-phase	$7.00	$10.40
	Three-phase	$11.00	$17.70
Daily Customer Charge:	Single-phase	$0.2301	$0.3419
	Three-phase	$0.3616	$0.5819
Energy Charge (per kWh)		$0.12061	$0.11143
Rg-3 OTOU RESIDENTIAL OPTIONAL TOU - Urban			
Equivalent Monthly Customer Charge:	Single-phase	$5.70	$10.40
	Three-phase	$9.70	$17.70
Daily Customer Charge:	Single-phase	$0.1874	$0.3419
	Three-phase	$0.3189	$0.5819
Energy Charge (per kWh):			
On Peak		$0.20739	$0.19998
Off Peak		$0.06842	$0.06305
Water Heater:			
Control Charge		$4.80	$4.80
Control Charge - Seasonal		$9.60	$9.60
Rg-4 OTOU RESIDENTIAL OPTIONAL TOU - Rural (Closed and Customers moved to Rg-3)			
Equivalent Monthly Customer Charge:	Single-phase	$7.00	$10.40
	Three-phase	$11.00	$17.70
Daily Customer Charge:	Single-phase	$0.2301	$0.3419
	Three-phase	$0.3616	$0.5819
Energy Charge (per kWh):			
On Peak		$0.20739	$0.19998
Off Peak		$0.06842	$0.06305
Water Heater Control Charges:		Same as Rg-3	Same as Rg-3

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions		Present Rates	Authorized Rates
Rg-5 OTOU URBAN RESIDENTIAL			
OPTIONAL 3-Tier TOU			
All Customer Charges		Same as Rg-3	Same as Rg-3
Energy Charge (per kWh):			
On-Peak		$0.27476	$0.25414
Standard		$0.12061	$0.11143
Off-Peak		$0.06842	$0.06305
Water Heater Control Charges:		Same as Rg-3	Same as Rg-3
Rg-6 OTOU RURAL RESIDENTIAL			
OPTIONAL 3-Tier TOU (Closed and Customers moved to Rg-5)			
All Customer Charges		Same as Rg-4	Same as Rg-3
Energy Charge (per kWh):			
On-Peak		$0.27476	$0.25414
Standard		$0.12061	$0.11143
Off-Peak		$0.06842	$0.06305
Water Heater Control Charges:		Same as Rg-3	Same as Rg-3
Rg-RR, RESPONSE REWARDS			
All Customer Charges		Same as Rg	Same as Rg
Energy Charge (per kWh):			
Critical Peak		$1.00000	$1.00000
On-Peak		$0.22459	$0.21477
Off-Peak		$0.06842	$0.06305
Cg-1 SMALL C&I (<50 kW)			
Equivalent Monthly Customer Charge:	Single-phase	$7.25	$12.50
	Three-phase	$10.25	$17.70
Daily Customer Charge:	Single-phase	$0.2384	$0.4110
	Three-phase	$0.3370	$0.5819
Energy Charge (per kWh)		$0.12061	$0.11525
Cg-2 SMALL C&I (<50 kW) -- Closed and Customers moved to Cg-1			
Equivalent Monthly Customer Charge:	Single-phase	$8.50	$12.50
	Three-phase	$11.50	$17.70
Daily Customer Charge:	Single-phase	$0.2795	$0.4110
	Three-phase	$0.3781	$0.5819
Energy Charge (per kWh)		$0.12061	$0.11525

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions		Present Rates	Authorized Rates
Cg-1-RR, RESPONSE REWARDS			
All Customer Charges		Same as Cg-1	Same as Cg-1
Energy Charge (per kWh):			
Critical Peak		$1.00000	$1.00000
On-Peak		$0.22459	$0.21477
Off-Peak		$0.06842	$0.06305
Cg-2-RR, RESPONSE REWARDS (Closed and Customers moved to Cg-1-RR)			
All Customer Charges		Same as Cg-2	Same as Cg-2
Energy Charge (per kWh):			
Critical Peak		$1.00000	$1.00000
On-Peak		$0.22607	$0.21477
Off-Peak		$0.06990	$0.06305
Cg-3 OTOU C&I OPTIONAL TOU - Urban			
Equivalent Monthly Customer Charge:	Single-phase	$7.25	$12.50
	Three-phase	$10.25	$17.70
Daily Customer Charge:	Single-phase	$0.2384	$0.4110
	Three-phase	$0.3370	$0.5819
Energy Charge (per kWh):			
On Peak		$0.20739	$0.20392
Off Peak		$0.06842	$0.06305
Water Heater Control Charges:		Same as Rg-3	Same as Rg-3
Cg-4 OTOU C&I OPTIONAL TOU - Rural (Closed and Customers moved to Cg-3)			
Equivalent Monthly Customer Charge:	Single-phase	$8.50	$12.50
	Three-phase	$11.50	$17.70
Daily Customer Charge:	Single-phase	$0.2795	$0.4110
	Three-phase	$0.3781	$0.5819
Energy Charge (per kWh):			
On Peak		$0.20739	$0.20392
Off Peak		$0.06842	$0.06305
Water Heater Control Charges:		Same as Rg-3	Same as Rg-3
Cg-5 SMALL C&I (50 < kW > 100)			
Equivalent Monthly Customer Charge:	Single-phase	$15.00	$31.50
	Three-phase	$19.00	$36.50
Daily Customer Charge:	Single-phase	$0.4932	$1.0356
	Three-phase	$0.6247	$1.2000
Energy Charge (per kWh)		$0.10324	$0.10000

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions		Present Rates	Authorized Rates
Cg-5-RR, RESPONSE REWARDS			
All Customer Charges		Same as Cg-5	Same as Cg-5
Energy Charge (per kWh):			
Critical Peak		$1.00000	$1.00000
On-Peak		$0.16152	$0.15565
Off-Peak		$0.06400	$0.06226
Cg-20-TOU C&I (100-1000 kW)			
Equivalent Monthly Customer Charge:	Secondary	$30.50	$59.50
	Primary	$58.30	$113.60
Daily Customer Charge:	Secondary	$1.0027	$1.9562
	Primary	$1.9167	$3.7348
Customer Demand Charge		$1.468	$1.689
Standby Demand Charge		$1.956	$2.251
System Demand Charge:	Summer	$10.865	$12.000
	Winter	$7.446	$7.750
Energy Charge (per kWh):			
On Peak		$0.07232	$0.06600
Off Peak		$0.04312	$0.03907
Energy Limiter (per kWh):		$0.17194	$0.16897
Cg-20 RESPONSE REWARDS			
All Customer Charges		Same as Cg-20	Same as Cg-20
System Demand Charges:			
Summer		$8.149	$9.000
Winter		$5.585	$5.813
Energy Charge (per kWh):			
Critical Peak		$0.39852	$0.40000
On-Peak		$0.04640	$0.05777
Off-Peak		$0.03852	$0.03542
Cp LARGE C&I (>1000 kW)			
Equivalent Monthly Customer Charge:	Secondary	$341.00	$665.00
	Primary	398.00	776.00
	Transmission	909.00	1,773.00
Daily Customer Charge:	Secondary	$11.2110	$21.8630
	Primary	$13.0849	$25.5123
	Transmission	$29.8849	$58.2904
Distribution Demand Charge:			
Secondary		$2.080	$2.260
Primary		$1.830	$1.990

(Continued on next page)

Wisconsin Public Service Corporation

SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions	Present Rates	Authorized Rates
Cp LARGE C&I (>1000 kW) -- continued		
Substation - Transformer Capacity Charge:		
Transmission	$0.583	$0.633
Standby Demand Charge	$3.50	$3.50
System Demand Charge:		
Peak:		
Summer (Sec.)	$11.355	$14.080
Summer (Pri.)	11.179	13.712
Summer (Trans.)	11.006	13.500
Winter (Sec.)	6.254	7.040
Winter (Pri.)	6.157	6.856
Winter (Trans.)	6.062	6.750
Intermediate:		
Summer (Sec.)	$8.516	$10.560
Summer (Pri.)	8.384	10.284
Summer (Trans.)	8.255	10.125
Winter (Sec.)	4.691	5.280
Winter (Pri.)	4.618	5.142
Winter (Trans.)	4.547	5.063
Interruptible Demand Charge[1]		
Summer (Sec.)	$5.054	$7.779
Summer (Pri.)	4.878	7.411
Summer (Trans.)	4.705	7.199
Winter (Sec.)	3.103	3.889
Winter (Pri.)	3.006	3.705
Winter (Trans.)	2.911	3.599
Interruptible Credit[1]		
Summer	(6.301)	(6.301)
Winter	(3.151)	(3.151)
Note[1] Interruptible Demand = Net of Firm Demand & Interruptible Credit		
Energy Charge:		
On-Peak (Secondary)	$0.06272	$0.05904
On-Peak (Primary)	0.06144	0.05784
On-Peak (Transmission)	0.06069	0.05714
Off-Peak (Secondary)	0.03484	0.03286
Off-Peak (Primary)	0.03413	0.03219
Off-Peak (Transmission)	0.03372	0.03179
Power Factor Discount (Pri, Sec, Trans)	92.44%	92.44%

Wisconsin Public Service Corporation

SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions	Present Rates	Authorized Rates
Cp-RR RESPONSE REWARDS		
All Customer Charges	Same as Cp	Same as Cp
System Demand Charge:		
Peak:		
Summer (Sec.)	$8.516	$10.560
Summer (Pri.)	8.384	10.284
Summer (Trans.)	8.255	10.125
Winter (Sec.)	4.691	5.280
Winter (Pri.)	4.618	5.142
Winter (Trans.)	4.547	5.063
Intermediate:		
Summer (Sec.)	$6.387	$7.920
Summer (Pri.)	6.288	7.713
Summer (Trans.)	6.191	7.594
Winter (Sec.)	3.518	3.960
Winter (Pri.)	3.464	3.857
Winter (Trans.)	3.410	3.797
Energy Charge:		
Critical (Sec.)	$0.40000	$0.40000
Critical (Pri.)	$0.38940	$0.39185
Critical (Trans.)	$0.38410	$0.38709
On-Peak (Sec.)	$0.04399	$0.03917
On-Peak (Pri.)	$0.04283	$0.03837
On-Peak (Trans.)	$0.04225	$0.03790
Off-Peak (Sec.)	$0.03161	$0.02956
Off-Peak (Pri.)	$0.03077	$0.02896
Off-Peak (Trans.)	$0.03035	$0.02861
Cp-ND NEXT DAY PRICING OPTION (Closed to New Customers)		
System Demand Charges:	Same as Cp	Same as Cp
Off-Peak Charges	Same as Cp	Same as Cp
On-Peak Charges:		
Critical Day		
Secondary	$0.11293	$0.10006
Primary	$0.11063	$0.09802
Transmission	$0.10929	$0.09683
Peak Day		
Secondary	$0.07734	$0.06718
Primary	$0.07576	$0.06581
Transmission	$0.07484	$0.06501
Mid-Economy Day		
Secondary	$0.06201	$0.05466
Primary	$0.06075	$0.05355
Transmission	$0.06001	$0.05290
Economy Day		
Secondary	$0.02700	$0.04614
Primary	$0.02644	$0.04520
Transmission	$0.02612	$0.04465

Wisconsin Public Service Corporation

SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions	Present Rates	Authorized Rates
Ms-31 MUNICIPAL ORNAMENTAL LIGHTING		
(Closed To New Cus tomers)		
Energy Charge	$0.06528	$0.06528
LS-1 STREET LIGHTING -- (Monthly Charges)		
-------------- Company Owned --------------		
Sodium Vapor		
5,670 Lumens (70W)	$17.00	$17.00
9,000 Lumens (100W)	17.52	17.52
14,000 Lumens (150W)	20.00	20.00
27,000 Lumens (250 W)	24.65	24.65
45,000 Lumens (400W)	33.06	33.06
9,000 Lumens (100W) Area	12.93	12.93
14,000 Lumens (150W) Area	15.76	15.76
27,000 Lumens (250 W) Directional	29.90	29.90
45,000 Lumens (400W) Directional	36.56	36.56
-------------- Company Owned --------------		
Metal Halide		
8,500 Lumens (150W)	$23.55	$23.55
26,000 Lumens (350W)	29.88	29.88
36,000 Lumens (400W) *	33.06	33.06
26,000 Lumens (350 W) Directional	31.91	31.91
36,000 Lumens (400W) Directional *	36.30	36.30
110,000 Lumens (1000 W)	55.00	55.00
LED		
9,000 Lumens (100W) SV equivalent	$17.52	$17.52
14,000 Lumens (150W) SV equivalent	20.00	20.00
27,000 Lumens (250W) SV equivalent	24.65	24.65
Note: * (above) indicates categories that are closed		
------- Customer Owned (closed) -------		
Sodium Vapor		
9,000 Lumens (100W)	$11.96	$11.96
14,000 Lumens (150W)	14.08	14.08
27,000 Lumens (250 W)	18.00	18.00
45,000 Lumens (400W)	22.04	22.04
Metal Halide		
8,500 Lumens (150W)	$16.82	$16.82
26,000 Lumens (350W)	21.04	21.04

(Continued on next page)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions	Present Rates	Authorized Rates
LS-1 STREET LIGHTING -- (Monthly Charges continued)		
---------------- Common ----------------		
Wood Poles	$5.08	$5.08
Fiberglass Poles 25' / 20'	8.47	8.47
Fiberglass Poles 30' / 25'	10.94	10.94
Fiberglass Poles 35' / 30'	13.70	13.70
Fiberglass Poles 40' / 35'	22.79	22.79
Spans	2.24	2.24
Excess Footage - Mast Arm	0.23	0.23
NATURE WISE		
NAT-R	$2.40	$2.40
NAT-C	$2.40	$2.40
ATS - AUTOMATIC TRANSFER SWITCH		
Monthly Customer Charge:		
Total Charge	$667.00	$667.00
Maintenance Only	$230.00	$230.00
Daily Customer Charge:		
Total Charge	$21.9288	$21.9288
Maintenance Only	$7.5616	$7.5616
PARALLEL GENERATION (PG-2A, PG-2B)		
Equivalent Monthly Customer Charge	$10.00	$20.00
Daily Customer Charge	$0.3288	$0.6575
Energy Credits:		
WPSC 's energy factors are based on LMP prices and are adjusted by delivery voltage to reflect losses. The PG-2A rates reflect Historic Day Ahead LMPs and PG-2B rates reflect actual LMPs. Payments are per kWh for On-Peak and Off-Peak energy.	Rates adjusted automatically in late 2012 for 2013	Rates are automatically adjusted in late 2013
Historic Day Ahead LMP base rate factors (per kWh):		
PG-2A On-Peak Energy Factor	$0.03271	TBD for 2014
PG-2A Off-Peak Energy Factor	$0.02218	TBD for 2014

Wisconsin Public Service Corporation

SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedules, Rate Classes & Rate Descriptions	Present Rates	Authorized Rates
Electric Embedded Allowances (per customer except as noted)		
Residential Customers (Rg-1 thru Rg-6)		
Year-Round Customers	$360.00	$425.00
Seasonal Customers	180.00	213.00
Commercial & Industrial (Cg under 100 kW)		
Estimated Demand of 0 to 15 kW		
Year-Round Customers	$425.00	$425.00
Seasonal Customers	213.00	213.00
Estimated Demand of 16 to 50 kW		
Year-Round Customers	$1,065.00	$1,060.00
Seasonal Customers	533.00	530.00
Estimated Demand of 51 kW & over		
Year-Round Customers	$2,280.00	$2,470.00
Seasonal Customers	1,140.00	1,235.00
Commercial & Industrial (Cg over 100 kW & Cp) per kW	$27.00	$27.00
Act 141 Cost in Base Rates (per kWh)		
For Rg-1 thru Rg-6	$0.00183	$0.00198
For Cg-1 thru Cg-5, Cg-20, Cp, & Ls-1	$0.00139	$0.00175
Approx. Act 141 $ in Large Energy Customer Rates	Specific to each customer	
Electric Revenue Stabilization Mechanism - 2012 Rate Adjustments[1]		
Residential & Commercial Non-Demand Classes:		
Rg-1 thru Rg-6, Cg-1 thru Cg-5		($0.00202)
Medium Commercial (Demand Metered) Class:		
Cg-20		($0.00173)

Note[1] -- Revenue Stabilization Mechanism Adjustments are included in the energy charges listed above and sunset on December 31,2014.

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Daily Customer Charge - (Rg-3)	$ 0.2301	$ 0.3370
Daily Customer Charge - Seasonal Service (Rg-3)	$ 0.4602	$ 0.6740
Daily Customer Charge - (Rg-T)	$ 0.3369	$ 0.3370
Telemetering Charge (Cg-Rg-T)	$ 0.5589	$ 0.3814
Daily Transportaion Administrative Charge (Rg-T)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge - (Rg-3)	$ 0.2427	$ 0.1824
Distribution Service Charge - (Rg-T)	$ 0.2193	$ 0.1824
Daily Balancing Charge	$ 0.0007	$ 0.0007
Gas Acquisition Charge (Rg-3)	$ 0.0265	$ 0.0257
Standard Commercial (Cg-FST, Annual Usage < 2,000 therms)		
Daily Customer Charge	$ 0.2301	$ 0.3370
Daily Customer Charge - Seasonal	$ 0.4602	$ 0.6740
Volumetric Charges:		
Distribution Service Charge	$ 0.2427	$ 0.1824
Daily Balancing Charge	$ 0.0007	$ 0.0007
Gas Acquisition Charge	$ 0.0265	$ 0.0257
Small Commercial (Annual Usage 2,001 - 20,000 therms)		
Daily Customer Charge - (Cg-FS)	$ 0.6904	$ 0.9863
Daily Customer Charge - Seasonal (Cg-FS)	$ 1.3808	$ 1.9726
Daily Customer Charge - (Cg-TS, TSA)	$ 0.9863	$ 0.9863
Telemetering Charge (Cg-TS)	$ 0.5589	$ 0.3814
Transportation Administrative Charge (Cg-TS, CG-TSA)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge - (Cg-FS)	$ 0.1211	$ 0.0949
Distribution Service Charge - (Cg-TS, TSA)	$ 0.1159	$ 0.1094
Daily Balancing Charge	$ 0.0007	$ 0.0007
Gas Acquisition Charge (Cg-FS)	$ 0.0245	$ 0.0238

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

		Present Rates		Authorized Rates
Medium Commercial (Annual Usage 20,001 - 200,000 therms)				
Daily Customer Charge - (Cg-FM)	$	3.1233	$	4.4384
Daily Customer Charge - Seasonal (Cg-FM)	$	6.2466	$	8.8768
Daily Customer Charge - (Cg-IM, Cg-SOS-M, TM, TMA, IEGM	$	4.4384	$	4.4384
Telemetering Charge (Cg-IM, Cg-TM, IEGM)	$	0.5589	$	0.3814
Transportation Administrative Charge (Cg-TM, Cg-TMA)	$	1.2329	$	1.2329
Volumetric Charges:				
Distribution Service Charge (FM)	$	0.0803	$	0.0652
Distribution Service Charge - (Cg-IM, Cg-SOS-M, TM, TMA,	$	0.0782	$	0.0750
Daily Balancing Charge	$	0.0007	$	0.0007
Gas Acquisition Charge (Gc-FM)	$	0.0245	$	0.0238
Gas Acquisition Charge (Gc-IM, Cg-SOS-M, IEGM)	$	0.0205	$	0.0199
Large Commercial (200,001 to 2,400,000)				
Daily Customer Charge	$	19.5616	$	19.5616
Daily Customer Charge - Seasonal (Cg-FL)	$	39.1233	$	39.1232
Telemetering Charge (Cg-FL, Cg-IL, Cg-TL, Cg-SOS-L)	$	0.5589	$	0.3814
Transportation Administrative Charge (Cg-TL, Cg-TLA)	$	1.2329	$	1.2329
Demand Charge	$	0.1475	$	0.1475
Volumetric Charges:				
Distribution Service Charge	$	0.0352	$	0.0336
Daily Balancing Charge	$	0.0007	$	0.0007
Gas Acquisition Charge (Cg-FL)	$	0.0175	$	0.0170
Gas Acquisition Charge (Cg-IL, Cg-SOS-L)	$	0.0160	$	0.0155
S-Large Commercial (> 2,400,000)				
Daily Basic Distribution Charge	$	127.6274	$	127.6274
Telemetering Charge (Cg-ISL, Cg-TSL)	$	0.5589	$	0.3814
Transportation Administrative Charge (Cg-TSL, Cg-TSLA)	$	1.2329	$	1.2329
Demand Charge	$	0.0833	$	0.0833
Volumetric Charges:				
Distribution Service Charge	$	0.0278	$	0.0271
Daily Balancing Charge	$	0.0007	$	0.0007
Gas Acquisition Charge (Cg-ISL)	$	0.0160	$	0.0155

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Interruptible Electric Generation (>200,000)		
Daily Basic Distribution Charge	$ 229.9726	$ 229.9726
Telemetering Charge	$ 0.5589	$ 0.3814
Demand Charge	$ 0.0649	$ 0.0649
Volumetric Charges:		
Distribution Service Charge	$ 0.0137	$ 0.0109
Daily Balancing Charge	$ 0.0007	$ 0.0007
Gas Acquisition Charge	$ 0.0135	$ 0.0131
Coal Displacement Gas Transportation		
Daily Basic Distribution Charge	$ 127.6274	$ 127.6274
Telemetering Charge	$ 0.5589	$ 0.3814
Transportation Administrative Charge (CDGT)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.0700	$ 0.0833
Volumetric Charges:		
Distribution Service Charge (CDGT)	$ 0.0199	$ 0.0237
Daily Balancing Charge	$ 0.0007	$ 0.0007
Base Average Cost of Gas Rates:		
Commodity ("Comm") rate	$ 0.3594	$ 0.3641
Peak Day Demand ("D1") rate	$ 0.1350	$ 0.1359
Annual Demand ("D2") rate	$ 0.0083	$ 0.0089
Balancing ("Bal") rate	$ 0.0062	$ 0.0060

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Act 141 Volumetric Distribution Rates 1/		
Residential (Rg-3)	$ 0.0093	$ 0.0092
Commercial & Industrial, Cg-ST (0 to 2,000)	$ 0.0106	$ 0.0094
Commercial & Industrial, Cg-S (2,001 to 20,000)	$ 0.0106	$ 0.0094
Commercial & Industrial, Cg-M (20,001 to 200,000)	$ 0.0106	$ 0.0094
Commercial & Industrial, Cg-L (200,001 to 2,400,000)	$ 0.0106	$ 0.0094
Commercial & Industrial, Cg-SL (> 2,400,000)	$ 0.0106	$ 0.0094
Interruptible Electric Generation, Cg-IEG (200,000+)	$ 0.0106	$ 0.0094
Coal Displacement Gas Transportation (CDGT)	$ 0.0106	$ 0.0094

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

	Present Rates	Authorized Rates
Gas Revenue Stabilization Mechanism - 2014 Rate Adjustment 2/		
Residential (Rg-3)	$ -	$ 0.0274
Commercial & Industrial, Cg-FST (0 to 2,000)	$ -	$ 0.0274
Commercial & Industrial, Cg-FS (2,001 to 20,000)	$ -	$ 0.0106
Commercial & Industrial, Cg-FM (20,001 to 200,000)	$ -	$ 0.0106

2/ Gas Revenue Stabilization Mechanism Adjustments are not included in the above volumetric distribution service charges and sunset on December 31, 2014.

Wisconsin Public Service Corporation
Gas Revenue Summary

Service Rate Classes	Volumes	Current Margin & Admin Revenues	+ Cost of Gas Revenues	= Rebundled Service Class Revenues	+ Authorized Distribution Rev Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled w/COG	Percent Change Rebundled w/o COG
Residential								
Residential (Rg-3)	222,349,691	$ 83,523,248	$ 108,688,097	$ 192,211,345	$ 3,424,048	$ 195,635,393	1.78%	4.10%
Residential - Seasonal (Rg-3)	1,058,374	$ 594,565	$ 401,161	$ 995,726	$ 107,773	$ 1,103,500	10.82%	18.13%
Subtotal	223,408,065	$ 84,117,814	$ 109,089,258	$ 193,207,072	$ 3,531,822	$ 196,738,893	1.83%	4.20%
Commercial & Industrial, Cg-ST (0 to 2,000)								
Firm Commercial (Cg-FST)	16,830,490	$ 6,162,365	$ 8,384,509	$ 14,546,874	$ 184,550	$ 14,731,423	1.27%	2.99%
Seasonal Commercial (Cg-FST)	25,598	$ 12,677	$ 9,703	$ 22,380	$ 1,816	$ 24,195	8.11%	14.32%
Subtotal Cg-ST	16,856,088	$ 6,175,042	$ 8,394,212	$ 14,569,253	$ 186,365	$ 14,755,618	1.28%	3.02%
Commercial & Industrial, Cg-S (2,001 to 20,000)								
Firm Commercial (Cg-FS)	70,578,908	$ 13,503,837	$ 34,549,345	$ 48,053,182	$ 215,999	$ 48,269,181	0.45%	1.60%
Seasonal Commercial (Cg-FS)	18,394	$ 3,951	$ 6,972	$ 10,923	$ 240	$ 11,163	2.20%	6.08%
Transport Commercial (Cg-TS)	187,224	$ 35,012		$ 35,012	$ (2,059)	$ 32,953	(5.88)%	(5.88)%
Transport-A Commercial (Cg-TSA)	357,903	$ 62,792		$ 62,792	$ (2,326)	$ 60,465	(3.70)%	(3.70)%
Interdepartmental (Cg-FS)	1,242,000	$ 192,792	$ 470,762	$ 663,554	$ (15,492)	$ 648,062	(2.33)%	(8.04)%
Subtotal Cg-S	72,384,429	$ 13,798,384	$ 35,027,079	$ 48,825,463	$ 196,362	$ 49,021,825	0.40%	1.42%
Commercial & Industrial, Cg-M (20,001 to 200,000)								
Firm Commercial (Cg-FM)	50,862,500	$ 6,713,934	$ 24,674,574	$ 31,388,508	$ 316,869	$ 31,705,377	1.01%	4.72%
Seasonal Commercial (Cg-FM)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
Interruptible Commercial (Cg-IM)	4,647,357	$ 516,509	$ 1,761,512	$ 2,278,020	$ (18,869)	$ 2,259,151	(0.83)%	(3.65)%
Transport Commercial (Cg-TM)	19,669,203	$ 1,999,034		$ 1,999,034	$ (74,194)	$ 1,924,839	(3.71)%	(3.71)%
Transport-A Commercial (Cg-TMA)	7,712,069	$ 893,801		$ 893,801	$ (24,679)	$ 869,122	(2.76)%	(2.76)%
Season-Opp Commercial (Cg-SOS-M)	1,045,861	$ 133,119	$ 396,418	$ 529,537	$ (3,974)	$ 525,563	(0.75)%	(2.99)%
Interruptible Electric Generation (Cg-IEGM)	16,683	$ 3,482	$ 6,323	$ 9,806	$ (128)	$ 9,678	(1.31)%	(3.68)%
Subtotal Cg-M	83,953,673	$ 10,259,878	$ 26,838,827	$ 37,098,705	$ 195,025	$ 37,293,730	0.53%	1.90%
Commercial & Industrial, Cg-L (200,001 to 2,400,000)								
Firm Commercial (Cg-FL)	9,232,405	$ 651,974	$ 4,183,890	$ 4,835,865	$ (14,061)	$ 4,821,803	(0.29)%	(2.16)%
Interruptible Commercial (Cg-IL)	4,432,781	$ 277,887	$ 1,680,180	$ 1,958,066	$ (3,429)	$ 1,954,637	(0.18)%	(1.23)%
Transport Commercial (Cg-TL)	122,215,573	$ 6,539,440		$ 6,539,440	$ (141,468)	$ 6,397,973	(2.16)%	(2.16)%
Transport-A Commercial (Cg-TLA)	930,804	$ 67,159		67158.5136	$ (1,489)	$ 65,669	(2.22)%	(2.22)%
Subtotal Cg-L	136,811,563	$ 7,536,459	$ 5,864,070	$ 13,400,529	$ (160,447)	$ 13,240,083	(1.20)%	(2.13)%
Commercial & Industrial, Cg-SL (> 2,400,000)								
Subtotal Cg-SL	179,757,395	$ 6,132,096	$ 2,220,436	$ 8,352,533	$ 3,803	$ 8,356,336	0.05%	0.06%
Interruptible Electric Generation, Cg-IEG (200,000+)								
Power Department (Cg-IEG)	20,276,000	$ 1,960,906	$ 7,685,316	$ 9,646,222	$ (65,596)	$ 9,580,626	(0.68)%	(3.35)%
Coal Displacement Gas Transportation (CDGT)	19,186,999	$ 306,726		$ 306,726	$ 107,806	$ 414,532	35.15%	35.15%
Act 141 Credits								
Total Gas Sales Revenues	752,634,212	$ 130,287,306	$ 195,119,198	$ 325,406,503	$ 3,995,140	$ 329,401,643	1.23%	3.07%
Plus:								
Other Gas Revenue				$ 1,239,076		$ 1,239,076		
Total Gas Operating Revenue				$ 326,645,579		$ 330,640,719	1.22%	

Monthly Residential Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Sales Service	0.3790	0.5149

Monthly Use Therms	2013 Rates with GRSM Credit: Customer Charge	Admin. & Distribut'n Charges	Gas Costs	Total Costs	2014 Rates without GRSM Credits: Customer Charge	Admin. & Distribut'n Charges	Gas Costs	Total Costs	Authorized Rates with 2014 GRSM Charge: Admin. & Customer Charges	Admin. & Distribut'n Charges	Gas Costs	Total Costs	Monthly Percent Increase (Decrease) 2013	Monthly Percent Increase (Decrease) 2014
Rg-1: Residential Firm Sales Service During Summer Months														
5	$ 7.00	$ 1.31	$ 1.90	$ 10.20	$ 7.00	$ 1.35	$ 1.90	$ 10.24	$ 10.25	$ 1.18	$ 1.90	$ 13.33	30.65%	30.10%
15	$ 7.00	$ 3.92	$ 5.69	$ 16.60	$ 7.00	$ 4.05	$ 5.69	$ 16.73	$ 10.25	$ 3.54	$ 5.69	$ 19.48	17.33%	16.41%
26	$ 7.00	$ 6.79	$ 9.85	$ 23.64	$ 7.00	$ 7.02	$ 9.85	$ 23.87	$ 10.25	$ 6.14	$ 9.85	$ 26.25	11.00%	9.95%
35	$ 7.00	$ 9.14	$ 13.27	$ 29.41	$ 7.00	$ 9.45	$ 13.27	$ 29.71	$ 10.25	$ 8.27	$ 13.27	$ 31.78	8.08%	6.97%
50	$ 7.00	$ 13.06	$ 18.95	$ 39.01	$ 7.00	$ 13.50	$ 18.95	$ 39.45	$ 10.25	$ 11.81	$ 18.95	$ 41.01	5.13%	3.97%
75	$ 7.00	$ 19.59	$ 28.43	$ 55.02	$ 7.00	$ 20.24	$ 28.43	$ 55.67	$ 10.25	$ 17.72	$ 28.43	$ 56.39	2.50%	1.30%
106	$ 7.00	$ 27.69	$ 40.18	$ 74.86	$ 7.00	$ 28.61	$ 40.18	$ 75.79	$ 10.25	$ 25.04	$ 40.18	$ 75.47	0.80%	(0.42)%
125	$ 7.00	$ 32.65	$ 47.38	$ 87.03	$ 7.00	$ 33.74	$ 47.38	$ 88.12	$ 10.25	$ 29.53	$ 47.38	$ 87.15	0.15%	(1.09)%
150	$ 7.00	$ 39.18	$ 56.86	$ 103.03	$ 7.00	$ 40.49	$ 56.86	$ 104.34	$ 10.25	$ 35.43	$ 56.86	$ 102.54	(0.48)%	(1.73)%
200	$ 7.00	$ 52.24	$ 75.81	$ 135.05	$ 7.00	$ 53.98	$ 75.81	$ 136.79	$ 10.25	$ 47.24	$ 75.81	$ 133.30	(1.29)%	(2.55)%
300	$ 7.00	$ 78.36	$ 113.71	$ 199.07	$ 7.00	$ 80.97	$ 113.71	$ 201.68	$ 10.25	$ 70.86	$ 113.71	$ 194.82	(2.13)%	(3.40)%
Rg-1: Residential Firm Sales Service During Winter Months														
5	$ 7.00	$ 1.31	$ 2.57	$ 10.88	$ 7.00	$ 1.35	$ 2.57	$ 10.92	$ 10.25	$ 1.18	$ 2.57	$ 14.01	28.74%	28.23%
15	$ 7.00	$ 3.92	$ 7.72	$ 18.64	$ 7.00	$ 4.05	$ 7.72	$ 18.77	$ 10.25	$ 3.54	$ 7.72	$ 21.52	15.43%	14.63%
26	$ 7.00	$ 6.79	$ 13.39	$ 27.18	$ 7.00	$ 7.02	$ 13.39	$ 27.40	$ 10.25	$ 6.14	$ 13.39	$ 29.78	9.57%	8.67%
35	$ 7.00	$ 9.14	$ 18.02	$ 34.16	$ 7.00	$ 9.45	$ 18.02	$ 34.47	$ 10.25	$ 8.27	$ 18.02	$ 36.54	6.96%	6.01%
50	$ 7.00	$ 13.06	$ 25.75	$ 45.80	$ 7.00	$ 13.50	$ 25.75	$ 46.24	$ 10.25	$ 11.81	$ 25.75	$ 47.81	4.37%	3.39%
75	$ 7.00	$ 19.59	$ 38.62	$ 65.21	$ 7.00	$ 20.24	$ 38.62	$ 65.86	$ 10.25	$ 17.72	$ 38.62	$ 66.58	2.11%	1.10%
106	$ 7.00	$ 27.69	$ 54.58	$ 89.27	$ 7.00	$ 28.61	$ 54.58	$ 90.19	$ 10.25	$ 25.04	$ 54.58	$ 89.87	0.67%	(0.36)%
125	$ 7.00	$ 32.65	$ 64.36	$ 104.01	$ 7.00	$ 33.74	$ 64.36	$ 105.10	$ 10.25	$ 29.53	$ 64.36	$ 104.14	0.12%	(0.91)%
150	$ 7.00	$ 39.18	$ 77.24	$ 123.41	$ 7.00	$ 40.49	$ 77.24	$ 124.72	$ 10.25	$ 35.43	$ 77.24	$ 122.92	(0.40)%	(1.45)%
200	$ 7.00	$ 52.24	$ 102.98	$ 162.22	$ 7.00	$ 53.98	$ 102.98	$ 163.96	$ 10.25	$ 47.24	$ 102.98	$ 160.47	(1.08)%	(2.13)%
300	$ 7.00	$ 78.36	$ 154.47	$ 239.83	$ 7.00	$ 80.97	$ 154.47	$ 242.44	$ 10.25	$ 70.86	$ 154.47	$ 235.58	(1.77)%	(2.83)%
Avg. Annual Residential Billing														
792	$ 83.99	$ 206.87	$ 386.61	$ 677.47	$ 83.99	$ 213.76	$ 386.61	$ 684.36	$ 123.01	$ 187.07	$ 386.61	$ 696.69	2.84%	1.80%

Service Rules, Sheet No. G10.03

8. PAYMENT OF BILLS: (Continued)

C. Minimum Payment Option (MPO): This option is available for residential customers who are faced with disconnection of utility service because of past-due utility bills. Customers will be given an option to pay a percentage of the total bill (arrearage and current bill) to avoid disconnection of service. The percentage will begin at 30% for the first disconnection notice due in the April billing cycle. It may increase or decrease for subsequent billing cycles by up to 10% for each succeeding month, but at no time will it exceed 60% of the balance as the minimum amount. If the customer pays the minimum payment option, and the following month the arrears still fall within the disconnection parameters, the customer will be given this minimum payment option again. ~~The starting percentage for the minimum amount will be 30% for the first disconnection notice due in April billing cycle. This minimum percentage will increase by 10% for each succeeding month. July, August, and September will require 60% of the balance as the minimum amount. Payment of the minimum amount will avoid disconnection of service.~~

~~If the customer pays the minimum payment option, and the following month the arrears still fall within the disconnection parameters, the customer will be given this Minimum Payment Option again.~~ The MPO will only be available ~~from~~ for the April ~~1~~ through September billing cycle~~30~~. Other payment options include full payment and deferred payment arrangements.

9. LATE PAYMENT CHARGE:

A. Utility service bills issued by the Company will include a late payment charge on all unpaid utility service balances. The late payment charge of 1 percent per month will be added to utility service bills not paid and credited prior to the succeeding monthly billing. Except as allowed by Sections 8. and 9.A.1. through 9.A.4., any utility service charges unpaid after 21 calendar days from the date of billing will be subject to a late payment charge. However, customers will have five ~~approximately seven~~ extra days ~~(the bill due date until the calculation date of the next bill)~~ to pay their bill and avoid late payment charges. The late payment charge will be applicable to all retail customers. The late payment charge will be applied to the total unpaid utility service balance including any unpaid late payment charges. Late payment charges will continue to compound until the past-due bill is deemed uncollectible. Other specific features of this late payment charge application include:

Extension Rules, Sheet No. G11.01

The Company reserves the right to review and recalculate the extension allowance after the five year development period in cases where the customer fails to meet the estimated annual gas usage (ER) and/or maximum daily gas demand (D) used in the original calculation.

Extension Rules, Sheet No. G11.03

3. EXTENSION OF GAS SERVICES:

B. The Allowance for a gas service line is calculated as follows:

2. "Allowable Service Line Footage" is defined as follows:

a. Residential and Commercial: The lesser of “F” from Section 3.A. above, or 60 trench feet as measured from the customer's property line that is most parallel to the Company's gas main from which the service line is installed to the meter riser. ~~service entrance; however, the Allowable Service Line Footage shall not extend beyond three feet on either side of the building wall fronting the gas main from which the service line is installed.~~

Extension Rules, Sheet No. G11.04

3. EXTENSION OF GAS SERVICES:

B. The Allowance for a gas service line is calculated as follows:

2. "Allowable Service Line Footage" is defined as follows:

b. Industrial: The lesser of “F” from Section 3.A. above, or 60 trench feet as measured from the customer's property line to the meter riser ~~service entrance~~.

C. See Section 8 regarding other possible Special Facilities Charges.

D. The meter location will be established by Company standards, in the Company’s sole discretion.

Extension Rules, Sheet No. G11.07

7. TITLE TO EXTENSION:

B. At the request of the Company, ~~As a condition of receiving gas service~~, the customer shall locate and mark permanent survey stakes indicating property lines and shall furnish, at no expense to the Company, recordable easements granting rights-of-way satisfactory to the Company for the design, installation, operation, and maintenance of the gas facilities along the entire route determined by the Company. The rights-of-way on applicant's property as designated by the Company shall be cleared of trees and other obstructions at applicant's expense. No buildings or trees shall be placed on said rights-of-way. The rights-of-way may be used for gardens, shrubs, landscaping and other purposes if they will not interfere with maintenance of gas facilities.

Extension Rules, Sheet No. G11.10

12. REPLACEMENT, RELOCATION AND/OR REBUILDING OF EXISTING FACILITIES:

B. Credit Allowances:

1. Where the replacement, relocation, or rebuilding of existing gas main ~~facilities~~ is required due to a customer's gas load growth, an estimated allowance, calculated per Section 2.B., with an "ER" equal to the customer's estimated annual incremental gas load, shall be applied to any such customer payment required. This allowance is not available in trailer and/or mobile home parks.

2. ~~1~~.Where the replacement, relocation, or rebuilding of existing gas service is required due to a customer's gas load growth, an allowance, calculated per Section 3.B., shall be applied to any such customer payment required. This allowance is not available in trailer and/or mobile home parks.

Gas Transportation Service, Sheet No. G7.61

6. SURCHARGE FOR UNAUTHORIZED USE OF GAS:
   A. The penalty rates described in Sections 6.A.1. and 6.A.2. below will be assessed against customers regardless of whether the Company is actually assessed penalties from the interstate pipeline(s) serving the Company's system, except as found in Section 15. Part B of this tariff.

Gas Transportation Service, Sheet No. G7.71

15. CONSTRAINT PERIODS
   B. Low Flow Constraint Periods
      4. Any customer, marketer, and/or its agent using less than the amount of gas delivered to the company's system during a Low Flow Constraint Period shall have unauthorized gas. The unauthorized gas shall be determined using company remote meter reading equipment or through daily and/or hourly meter reading obtained by the company. Daily undertake quantities shall be subject to the Surcharge for Unauthorized Use of Gas found in Section 6 of this tariff if the Company is assessed penalty charges and/or cycling fees by any interstate pipeline(s) during a Low Flow Constraint Period.

Revised Purchased Gas Adjustment Clause

Wisconsin Public Service Corporation (WPSC) shall calculate a purchased gas adjustment (PGA) each month to reflect changes to the base average gas costs. The PGA shall also include a reconciliation between the actual cost of gas supply and the amount recovered from customers during the PGA year. In addition to the PGA rate adjustment, the PGA filing may also include any refunds received by WPSC from its wholesale suppliers. All rate adjustments shall be taken to the nearest 0.01 cent per therm.

WPSC shall file with the Commission at least one business day prior to the first business day of each month the proposed rate changes under the operation of this PGAC schedule. Filings shall include the rate sheets, source data and supporting calculations. The PGAC rates shall be effective as of the first day of the month and upon Commission review may be subject to change and, if necessary, refund.

WPSC shall file with the Commission any deviations from WPSC's most recent approved Gas Supply Plan. Any change in sales data should be reflected in future PGAC filings. Any changes in firm capacity, storage, firm supply and any other reliability related change, such as capacity release without recall, must be filed with the Commission for approval at least 21 days prior to the effective date of the change.

For purposes of the operation of this schedule, the PGA year will be the period from November 1 through October 31, and the winter season shall be the period November 1 through April 30. Both periods are consistent with the planning periods from WPSC's Gas Supply Plan.

Base Average Gas Costs

A. The base average cost of gas as determined in docket 6690-UR-122, order date __________, is as follows:

Peak Day Demand ("D1") rate:	$0.1359/Therm
Annual Demand ("D2") rate:	$0.0089/Therm
Balancing ("Bal") rate:	$0.0060/Therm
Commodity ("Comm") rate:	$0.3641/Therm

When WPSC's cost of natural gas supply or sales data changes from the estimates reflected in the base average gas costs, new rates for average gas costs shall be calculated. The sources of supply, throughput data, and the purchased gas to sales ratio shall be from WPSC's most recent approved Gas Supply Plan.

B. New Average Gas Costs

1. NEW AVERAGE PEAK DAY DEMAND COSTS: WPSC's annual Wisconsin gas costs associated with peak day demand shall include, but not be limited to, pipeline capacity costs; storage service costs excluding those costs directly assigned to balancing costs; firm reservation charges from other suppliers which are used to meet peak day demand; less estimated annual peak day backup revenues, capacity release and opportunity sales credits. To more fairly allocate interstate pipeline transportation costs to all customers, a portion of the peak day demand costs will be allocated to annual demand costs based on the allocations reflected in WPSC's approved Gas Supply Plan. The new rate for average peak day demand costs shall be calculated by dividing WPSC's estimated peak day demand costs for the gas year by the total estimated firm therm sales from the approved Gas Supply Plan. The peak day demand rate will be collected from firm sales customers during the period from November 1st through April 30th.

2. NEW AVERAGE ANNUAL DEMAND COSTS: WPSC's annual Wisconsin gas costs associated with annual demand shall include, but not be limited to the allocated peak day demand costs described in Peak Day Demand Costs and any other costs identified as annual demand costs in WPSC's approved Gas Supply Plan less estimated annual capacity release and opportunity sales credits. The new rate for annual demand costs shall be calculated by dividing WPSC's estimated annual demand costs for the gas year by the total estimated firm and interruptible therm sales

from the approved Gas Supply Plan. The commodity rate is charged each month to all customers that purchase gas commodity from WPSC, except for transportation customers utilizing the daily cash-out mechanism.

3. NEW AVERAGE BALANCING COSTS: WPSC's annual Wisconsin gas costs associated with balancing shall include, but not be limited to, pipeline balancing service costs and firm pipeline transportation and storage service costs allocated to balancing less estimated daily balancing service revenues. The new rate for balancing costs shall be calculated by dividing WPSC's estimated balancing costs for the gas year by the total estimated firm and interruptible therm sales from the approved Gas Supply Plan. The balancing rate is charged each month to all customers that balance their usage on WPSC's system, except that balancing charges for transportation customers are defined in rate schedule GT.

4. NEW AVERAGE COMMODITY COSTS: The new average monthly commodity cost of gas shall reflect the actual gas storage activity leading up to the gas year and commodity sales, firm commodity contracts, sources of supply and estimated gas inventory activity for the gas year as reflected in WPSC's approved gas supply plan. The new rate for commodity costs shall be calculated by dividing WPSC's estimated commodity costs for the filed month by the filed month's estimated firm and interruptible therm sales from the approved Gas Supply Plan. The commodity rate is charged to all customers that purchase gas commodity from WPSC, except the commodity rate for transportation customers utilizing the daily cash-out mechanism as defined in rate schedule GT.

C. GAS COMMODITY BENCHMARK:

In accordance with the Commission's order in docket 6690-GR-100, WPSC will file monthly and annual comparisons of its actual per Therm cost of gas commodity with its benchmark per therm cost of gas commodity. The benchmark cost of gas commodity will be determined in accordance the Commission's order in docket 6690-GR-100, and WPSC's approved Gas Supply Plan.

D. RECONCILIATION OF GAS COSTS:

With the beginning of the new Gas Supply Plan year every November 1 through the following October 31, monthly, the booked cost of gas shall be compared to the cost of gas recovered. The cost of gas recovered (Peak Day Demand, Annual Demand, Balancing, and Commodity) is the sum of the respective base average cost of gas and the applicable purchased gas adjustments times the quantity of gas sold to which these rates were applied, and adjusted as described in new average gas costs. The amount of the differences shall be recovered from or returned to sales customers by a reconciliation adjustment over a period not less than one month. Such differences shall not be reflected in transportation customer's rates.

Pipeline Scheduling Penalty Charges: Charges assessed to WPSC by pipeline companies for exceeding limits of their balancing service(s) (sometimes referred to as scheduling charges, scheduling penalties, overrun penalties) except for those associated with a breach of contracted maximum daily quantity (MDQ) between WPSC and the pipeline shall be considered a normal purchased gas expense and shall be a collected through this PGAC. Assignment of such costs shall be based on the current assignment of charges for similar service.

Balancing Charges: Gas cost charges and penalties invoiced under all balancing services which have been collected shall be classified accordingly, allocated and billed to the appropriate customers.

Unauthorized Gas Charges: All gas charges and costs associated with unauthorized gas shall be classified by the above cost types and credited through this Purchased Gas Adjustment Gas Cost Recovery Mechanism.

E. PGA RATE ADJUSTMENT

The charge per therm for gas sold under all rate schedules shall be increased or decreased by the sum of I) the difference between the rate for new average gas costs and the rate for base average gas costs, 2) the monthly gas cost reconciliation for each of the base average gas cost components, and 3) any refunds received by WPSC from its wholesale suppliers. The net change in rates from this calculation will be identified as the PGA adjustment.

F. REFUND PROVISION

Natural gas cost-related refunds received by WPSC from its wholesale suppliers resulting from actions taken by the Federal Energy Regulatory Commission (wholesale refunds) shall be refunded to customers by means of the PGA schedule. Wholesale refunds shall be distributed to services eligible to receive refunds on the same basis by which related costs were collected.

Wisconsin Public Service Corporation
2014 Test Year Electric Net Generation, Fuel & Purchased Power Costs
for Fuel Monitoring
Docket # 6690-UR-122

With 11-4-13 NYMEX Unadjusted

MONTH	NET KWH PRODUCED	FUEL	MONTHLY FUEL COST PER NET KWH PRODUCED	CUMULATIVE COST PER NET KWH PRODUCED
JANUARY	1,175,553,794	$33,713,979	$0.02868	$0.02868
FEBRUARY	1,099,520,473	$31,336,427	$0.02850	$0.02859
MARCH	1,127,726,875	$30,339,608	$0.02690	$0.02803
APRIL	1,069,569,783	$28,641,008	$0.02678	$0.02773
MAY	1,097,943,312	$30,487,638	$0.02777	$0.02774
JUNE	1,184,379,362	$31,592,059	$0.02667	$0.02755
JULY	1,246,375,774	$34,080,287	$0.02734	$0.02752
AUGUST	1,233,831,465	$33,724,170	$0.02733	$0.02750
SEPTEMBER	1,136,089,449	$30,720,965	$0.02704	$0.02745
OCTOBER	1,086,544,179	$29,013,195	$0.02670	$0.02737
NOVEMBER	1,091,517,678	$29,480,138	$0.02701	$0.02734
DECEMBER	1,143,310,000	$31,083,217	$0.02719	$0.02733
TOTAL	**13,692,362,144**	**$374,212,691**	**$0.02733**	

NOTE 1. The above net Kwh produced is forecasted total generation plus purchased power less firm and non-firm opportunity sales, less Transmission Losses, Interdepartmental and Company Use as determined in the fuel monitoring process.

NOTE 2. The above fuel costs represent the fuel and purchased power costs included in the fuel monitoring budget. These fuel monitoring values exclude handling, ash disposal, capacity purchases, ATC & MISO Network Transmission charges and MISO Administrative Fees.

Wisconsin Public Service Corporation
Deferral Amortization Schedule

Deferral	PSCW Deferral Authorization	Notes	Amortization Period	Test Year Amount Electric	Test Year Amount Gas
DePere Energy Center Premium	6690-EB-104	4	2014-2023	$ 2,280,420	$0
Weston 3 Lightning - Purchased Power	5-GF-120 6690-UR-119	1	2014	2,800,000	0
Weston 3 Lightning - Purchased Power	5-GF-120 6690-UR-119	5	2014	825,058	0
Domestic Manufacturing Deduction and Research & Experimentation Tax Credits	6690-GF-115 6690-UR-119	4	2014	334,293	0
Tax Deferrals	Precedent	3	2014	306,482	(157,592)
Tax Deferrals	Precedent	3	2014	(662,512)	(176,111)
Farm Re-Wiring Escrow	6690-UR-121	3	2014	1,000,000	0
Conservation Escrow (pre-Act 141)	Various	3	2014	1,850,433	726,956
Conservation Escrow (Act 141)	Various	1	2014	13,900,421	4,394,533
Conservation Escrow Amortization Adjustment	Various	3	2014-2016	894,928	(851,117)
Additional Focus On Energy (FOE) payments	6690-UR-119	1	2014	(1,068)	(7,272)
WI Revenue Stabilization Mechanism (RSM)	6690-UR-119	1	2014	(12,764,456)	7,877,276
Manufactured Gas Plant Cleanup	6690-UR-110	2	2014-2017	0	3,488,966
Columbia Environmental Pre-certification	6690-GF-118 6690-UR-121	4	2014	358,392	0
Edgewater Environmental Pre-certification	6690-GF-118 6690-UR-121	4	2014	262,860	0
Edgewater Environmental Pre-construction	6690-GF-118 6690-UR-121	4	2014	40,162	0
CSAPR Costs	6690-UR-120 6690-UR-121	4	2014	2,374,463	0
Gain (Loss) on Disposal of Emission Allowances	6690-UR-113	4	2014	262,166	0
2012 Fuel Refund	6690-UR-120 6690-UR-121	1	2014	(1,095,000)	0
Production Tax Credits (Shift to Grants)	6690-UR-121	3	2014-2039	800,093	0
FUTA Deferral	05-GF-179	4	2014	25,640	6,580
2012 Wisconsin Retail Electric Fuel Cost Refund True-Up.	6690-UR-121	1	2014	(1,315,384)	0
2013 Deferred Incremental Fuel Related Costs	6690-UR-121	1	2014	(654,253)	0
2013 Deferred Incremental Transmission Related Costs.	6690-UR-121	1	2014	295,048	0
2013 Deferred Incremental Pension and Benefits Costs	6690-UR-121	1	2014	7,254,159	2,138,009
2013 Deferred Incremental Cost of Debt	6690-UR-121	1	2014	1,375,992	0
Glenmore Wind Asset Retirement	6690 (1/10/13 Accounting letter n PSC Ref #178828)	4	2014-2016	56,640	0
Crane Creek - Revenue Normalization	6690-UR-122	4	2014	1,373,227	0
Crane Creek - Depreciation Deferral	6690-UR-122	4	2014-2039	(344,791)	0
Fox Energy Center - Purchased Power Contract Buyout	6690-EB-105	3	2014-2022	5,555,556	0
Fox Energy Center - Utility Acquisition Adjustment	6690-EB-105	3	2014-2038	1,790,574	0
Fox Energy Center - Contract Service Agreement	6690-EB-105	3	2014-2020	2,224,715	0
Totals				$ 31,404,258	$ 17,440,228

(1) Amount applies to Wisconsin Retail customers only.
(2) Amount allocated between Wisconsin and Michigan Retail customers.
(3) Amount allocated between all WPSC jurisdictions. (WI, MI, FERC)
(4) Amount allocated between Wisconsin Retail and FERC Market Based customers.
(5) Amount applies to FERC Market Based Rate customers only.

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	6690-UR-122

CONCURRENCE AND DISSENT OF COMMISSIONER ERIC CALLISTO

While I join my colleagues in the Final Decision, I write separately solely to explain my dissenting position on the customer-owned Distributed Generation (DG) issues that relate to Wisconsin Public Service Corporation's (WPSC) Pg-4 tariff. These issues are covered on pages 51 through 59 of the Final Decision. I am specifically dissenting from the following regarding the Pg-4 tariff: (i) required monthly netting structure; (ii) 20 kilowatt (kW) capacity limit; (iii) net excess generation rate based on average locational marginal pricing (LMP); and (iv) refusal to open an investigation on DG regulatory policy issues.

On netting, I would have supported annual, rather than monthly, netting for the Pg-4 customers. Allowing for an annual approach is fair and consistent with the notion of allowing net metering customers to self-generate up to their actual use, an idea this Commission has historically supported. Monthly netting has the effect of artificially promoting the installation of systems that are smaller than would be sufficient to meet annual energy use. Other Wisconsin utilities, Wisconsin Electric Power Company, Madison, Gas and Electric Company, and Northern States Power Company among them, use an annual netting period, and I see no reason to treat WPSC any differently. If the Commission is concerned about fixed cost recovery issues and possible cross-subsidization, it should tackle those issues head on, rather than through a netting structure that penalizes DG customers who would prefer to size their systems to meet the annual load.

I also do not support moving to a 20 kW size limit. This is a move that will primarily impact business customers, and it will do so negatively, a measure that is particularly unjustified in our still slowly recovering economy. Here again, WPSC and the Commission make much of supposed fixed cost recovery problems and "potential" cross-subsidization, but there is very little record support for these claims. Commission staff has estimated that WPSC's Pg-4 customers account for a lost fixed cost recovery of about $100,000, which equals 0.01 percent of WPSC's total retail revenue requirement. I don't agree that a "potential" problem so small justifies making the Pg-4 tariff, an increasingly popular offering, largely unavailable to an entire class of business customers. I would have kept the capacity limit at 100 kW.

I think the record before us also supports a net excess generation rate for Pg-4 customers that embodies a more complete accounting of the avoided costs attributable to DG customers. The Commission's adoption of a flat, average LMP rate ignores the time of day at which Pg-4 customers are generating electricity. And average LMPs, which are in part based on nighttime prices, likely fall well short of reflecting the costs avoided by solar generation – which often occurs at higher-priced, on-peak times of the day. So I would have preferred an avoided cost methodology that more directly includes both on-peak and off-peak components. I have also long believed that avoided cost calculations should account for avoided capital costs, including avoided transmission costs, and it is not clear to me that the Commission's approach here will adequately and fully address capital cost components.

The regulatory issues raised by DG are not going away, and our piecemeal approach to addressing them isn't working well. We continue to send mixed signals to those affected by the DG issue, and the one-rate-case-at-a-time approach to DG policy has so far set us up for court challenge and protracted litigation. We owe it to the regulated and broader DG stakeholder community to articulate a coherent regulatory policy in this area. I would have supported opening an investigation to look at DG issues more broadly, the economics involved, the policy implications of various options before the Commission, and the possibility of alternatives or adjuncts to net metering.

I respectfully dissent.

DL: 00895792

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	6690-UR-122

CONCURRENCE AND DISSENT OF COMMISSIONER ELLEN NOWAK

While I join my colleagues in the Final Decision, I write separately to dissent from the Commission's adoption of the revenue allocation and use of the fuel over-collection in the Wisconsin Public Service Corporation rate case, docket 6690-UR-122. I understand the Commission's desire to reach a zero percent increase for all customers, but I disagree with the results-driven method used in this circumstance.

Specifically, I take issue with the process endorsed by the Commission in this case and the methodology used to set base rates before the 2013 fuel over-collection was reconciled in order to reach a zero percent increase.

Regarding the process, the Commission chose in this instance to use a procedure that is not contemplated in the fuel rules set forth in Wis. Admin. Code ch. PSC 116. Allocating the 2013 fuel over-collection prior to the reconciliation process is problematic. There is still potential for dramatic change in the last few months of the year, even if that potential is small. That said, the fact that several utilities are regularly over-collecting for fuel costs by a significant amount raises the question of whether the fuel rules are accomplishing their intended purpose of risk-sharing between the utility and ratepayers.

There is no question that any fuel over-collection should be returned on an energy-only basis, consistent with how fuel costs are collected. Here, in order to reach a zero increase for all customers, the majority chose to allocate the revenue deficiency on an energy-only basis in order for the fuel refund to zero out increases in every rate class. It is difficult to envision a scenario where allocation of a revenue deficiency on an energy-only basis would be supported by any cost-of-service study. Thus, the only reason such allocation was used in this rate case was to justify the early capture and refund of the fuel-over collection so that a zero percent increase could be achieved.

While I don't contend that the process was contrary to statute or administrative code, the process was introduced at the tail end of the rate case and without the support of all of the parties. While consent by all of the parties for this process is not needed, the Commission did ask for their input and at least implied that this unique process would only be used if all of the parties agreed.

I understand that the difference between using a more traditional revenue allocation and the method used by the majority in this case would be minimal, but using 2013's fuel over-collection to offset 2014's revenue deficiency is a change from our usual procedures that deserved support from all of the parties.

DL: 00895751