Founded in 1852
by Sidney Davy Miller

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September 26, 2012

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
Lansing, MI 48911

Re: Wisconsin Public Service Corporation
2013 PSCR Plan and Factors
MPSC Case No. U-17092

Dear Ms. Kunkle:

Enclosed for electronic filing are the Application and Direct Testimony and Exhibits of John G. Guntlisbergen together with the Appearance of Sherri A. Wellman.

Please be advised that a marked-up Notice of Hearing has been e-mailed to jonesg1@michigan.gov.

Should you have any questions, please kindly advise.

Very truly yours,

Miller, Canfield, Paddock and Stone, P.L.C.

Sherri A. Wellman
Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman C = US O = Miller Canfield
Date: 2012.09.26 10:16:46 -05'00'

By: ______________________________
Sherri A. Wellman

Enclosure(s)

cc: John G. Guntlisbergen

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MICHIGAN DEPARTMENT OF LABOR AND ECONOMIC GROWTH
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at (517) 241-6170.

Please Note: The commission will provide service of documents in this proceeding to only one person for each party.

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Wisconsin Public Service Corporation Docket No. U-17092

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name)	Wisconsin Public Service Corporation
2. (Name)	
3. (Name)	
4. (Name)	
5. (Name)	
6. (Name)	
7. (Name)	

Name SHERRI A. WELLMAN

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Email wellmans@millercanfield.com

Date 09/26/2012

Signature: Sherri A. Wellman

Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman C = US O = Miller Canfield
Date: 2012.09.26 10:17:00 -05'00'

☐ I am not an attorney

☒ I am an attorney whose:

Michigan Bar # is P- 38989

______ Bar # is: ______
(state)

EAHR1 - 10/23/06

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
WISCONSIN PUBLIC SERVICE CORPORATION	)	Case No. U-17092
for approval of a power supply cost recovery plan and	)	
authorization of monthly power supply cost recovery factors	)	
for the calendar year 2013, and other related approvals.	)	
____	)	

<u>APPLICATION</u>

WISCONSIN PUBLIC SERVICE CORPORATION ("WPS Corp") applies for authority from the Michigan Public Service Commission ("Commission") pursuant to Section 6j of 1982 PA 304 ("Act 304") to implement a Power Supply Cost Recovery ("PSCR") plan and establish a PSCR factor for the calendar year 2013. Additionally, WPS Corp seeks to recover through the PSCR mechanism, costs and credits associated with Financial Transmission Rights ("FTR") and the impacts from the use of natural gas and heating oil futures and options contracts for the purpose of hedging fuel and purchased power costs. In support of this Application, WPS Corp respectfully represents the following:

1. WPS Corp, a wholly-owned subsidiary of Integrys Energy Group, Inc., is a public service corporation organized under the laws of the state of Wisconsin, with its principal office located in Green Bay, Wisconsin, and is authorized to do business in the state of Michigan. WPS Corp is engaged in the generation, distribution, and sale of electric energy in service areas

located in Northeastern Wisconsin and in an adjacent part of Menominee County in the Upper Peninsula of Michigan.

2. WPS Corp's Michigan retail electric business is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; and 1939 PA 3, as amended, MCL 460.1 et seq.

3. WPS Corp's current Michigan retail electric rates were authorized by the Commission pursuant to its order issued in Case No. U-15352, dated December 4, 2007. Reflected in the base rates are power supply costs of 38.79 mills per kilowatt-hour ("MWh") and a PSCR loss factor of 1.0492.

4. In accordance with Act 304 and this Commission's August 1, 1984 Opinion and Order in Case No. U-7804 authorizing WPS Corp's PSCR clause, WPS Corp files the testimony and exhibits of John G. Guntlisbergen, which constitutes its 2013 PSCR plan and factor of positive $3.94 per MWh to be implemented in its retail Michigan electric customers' monthly bills for the January 2013 through December 2013 billing months. WPS Corp does not propose to roll in a forecasted over/under recovery for 2012 as the Company is forecasting an over/under recovery of zero.

5. In its August 1, 1984 Opinion and Order in Case No. U-7805, this Commission exempted WPS Corp from filing any further five-year forecasts and underlying information concerning fuel contracts and power supply arrangements. WPS Corp's plan, as described in its testimony and exhibits, is filed pursuant to such exemptions.

6. WPS Corp represents that its 2013 PSCR plan and factors, as filed in this case, are just, reasonable, and in the public interest.

7. WPS Corp is also requesting authority to recover through the PSCR prudently incurred actual costs and credits associated with FTRs and the impacts associated with hedging fuel and purchased power costs. Similar authority has been previously granted in Case Nos. U-14708, U-15008, U-15402, U-15662, U-16032, U-16422, and U-16882.

WHEREFORE, WPS Corp respectfully requests that this Commission:

A. Make and issue its order and notice of hearing, and after notice and hearing;

B. Determine that the decisions underlying WPS Corp's power supply cost recovery plan are reasonable and prudent;

C. Approve the power supply cost recovery plan as proposed by WPS Corp;

D. Approve the 2013 power supply cost recovery factor of positive $3.94 per MWh as requested by WPS Corp in its power supply cost recovery plan;

E. Continue the approval for PSCR recovery of costs and credits associated with FTRs and hedging of fuel and purchased power costs; and

F. Grant WPS Corp such other and further authority as may be lawful and proper.

Respectfully submitted,

WISCONSIN PUBLIC SERVICE CORPORATION

Sherri A. Wellman

Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman C = US O = Miller Canfield
Date: 2012.09.26 10:17:17 -05'00'

Dated: September 26, 2012 By: ______________________

Its Attorney
Sherri A. Wellman (P38989)
MILLER, CANFIELD, PADDOCK AND STONE, PLC
One Michigan Avenue, Suite 900
Lansing, MI 48933-1609
(517) 487-2070

Attorney for Wisconsin Public Service Corporation

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STATE OF MICHIGAN

BEFORE THE

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **WISCONSIN PUBLIC SERVICE CORPORATION** for approval of a power supply cost recovery plan, and authorization of monthly power supply cost recovery factors for the calendar year 2013 and other related approvals.	**)** **)** **)** **)** **)** **)**	Case No. U-17092

DIRECT TESTIMONY AND EXHIBITS OF

JOHN G. GUNTLISBERGEN

9-26-12

Q. Please state your name, business address, and position.

A. My name is John G. Guntlisbergen. My business address is Integrys Energy Group, Inc. ("Integrys"), 700 North Adams Street, P.O. Box 19001, Green Bay, WI 54307-9001. I am the Manager of Electric Fuel Cost Recovery in the Regulatory Affairs Department of Integrys. Wisconsin Public Service Corporation ("WPS Corp" or the "Company") is a wholly-owned subsidiary of Integrys.

Q. Please describe briefly your education, professional, and utility background.

A. In 1981, I graduated from St. Norbert College - De Pere, Wisconsin, with a Bachelor of Business Administration Degree in Accounting. After completing college I was employed by WPS Corp as a Depreciation Analyst and later as the Depreciation Supervisor in the Corporate Tax Department. While in the Corporate Tax Department, I performed depreciation studies on utility plant property, and determined book depreciation, tax depreciation and deferred taxes on an actual and forecasted basis. In 1993, I moved to the Rates and Economic Evaluation Department as a Rates Planner. I performed cost studies and rate impact studies for generation planning and long-range corporate planning. I participated in the analysis of transmission costs and the development of the transmission tariffs for filing with the Federal Energy Regulatory Commission ("FERC"). I performed electric and gas cost of service studies for the Michigan and Wisconsin jurisdictions. I have also worked with the power supply areas for WPS Corp and Upper Peninsula Power Company to develop Power Supply Cost Recovery ("PSCR") plans and in the reconciliation of the PSCR costs to revenues.

Q. Have you ever testified before a regulatory agency?

A. Yes. I have testified before the Public Service Commission of Wisconsin ("PSCW") and the Michigan Public Service Commission ("MPSC").

Q. What is the nature of the testimony you are offering in this proceeding?

A. The purpose of my testimony is (1) to support the Company's 2013 PSCR plan, (2) to develop the 2013 PSCR factors, and (3) to support the cost recovery of financial instruments used to hedge fuel and purchased power costs.

The proposed PSCR factors were calculated using WPS Corp's most recent estimates of generation requirements, fuel and transmission costs for 2013.

Q. Are you sponsoring any exhibits in the proceeding?

A. Yes, I am sponsoring Exhibit A-1 (JGG-1) and Exhibit A-2 (JGG-2).

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-1 (JGG-1).

A. Exhibit A-1 (JGG-1) consists of six pages.

Page 1 shows the calculation of the uniform PSCR factor for January through December 2013.

Page 2 details the anticipated power supply costs by function for each month for January through December 2013.

Page 3 shows the actual power supply dispatch and the related costs for the first seven months of 2012.

Page 4 shows the forecasted power supply dispatch and the related costs for all 12 months of 2013.

Page 5 compares the first 7 months of actual power supply costs for 2012 to the first 7 months of the forecasted power supply costs for the 2013 plan year.

Page 6 shows the January through August 2012 actual over/under-recovery of power supply costs as requested in item 5 of the Commission Staff Additional Filing Requirements - PSCR Plans. Page 6 also shows a forecast of the September through December 2012 over/under-recovery of power supply costs.

Pages 3 and 5 of Exhibit A-1 (JGG-1) are in response to item 1 of the ongoing Commission Staff discovery request in Case No. U-8587 entitled "Additional Filing Requirements - PSCR plans". (WPS Corp’s submittal of pages 3 and 5 with this case should not imply that the Company agrees that these pages are relevant to the proposed 2013 plan.)

Q. Please describe Exhibit A-2 (JGG-2).

A. Page 1 of Exhibit A-2 (JGG-2) is the PSCR schedule Sheet No. D-1.00 of WPS Corp's Michigan rate book revised to reflect the proposed PSCR factor of $0.00394 per kilowatt-hour (or $3.94 per MWh) to be applied for all billing months during 2013.

Q. What are the PSCR clause base and the loss factor used in the determination of the PSCR factor in this case?

A. The current PSCR clause base is $38.79/MWh on a generation basis and the loss factor is 1.0492 as established in the Company's most recent rate case before the MPSC, Case No. U-15352. Applying the loss factor to the PSCR clause base on a generation basis results in a PSCR clause base of $40.70/MWh on a requirement sales basis, which is used in the determination of the PSCR factor as shown on line 7 of page 1 of Exhibit A-1 (JGG-1).

Q. How was the proposed $3.94/MWh power supply cost recovery factor determined?

A. Referring to the annual total column on page 1 of Exhibit A-1 (JGG-1), the proposed $3.94/MWh power supply cost recovery factor was determined by: (a) dividing the total system costs for recovery on line 1 of $598,297,000, by the net system requirements excluding losses on line 2 of 13,402,631 MWhs, resulting in the corporate average power supply cost of $44.64/MWh on line 3. (b) This average power supply cost/MWh was applied to the estimated 2013 Michigan retail sales of 287,688 MWhs on line 4, resulting in the net power supply costs assigned to the Michigan retail jurisdiction of $12,842,000 on line 5. (c) Dividing the adjusted net power supply costs assigned to the Michigan jurisdiction of $12,842,000 by the estimated 2013 Michigan retail sales on line 4, resulted in the Michigan power supply cost rate of $44.64/MWh on line 6. (d) Comparing the $44.64/MWh of power supply cost to the base power supply costs included in base rates of $40.70/MWh on line 7, results in the proposed $3.94/MWh power supply cost recovery factor on line 8. (e) The forecasted 2012 over/under-collection roll-in is $0.00/MWh (line 9). (f) The 2013 PSCR factor with the roll-in of the estimated 2012 over/under-collection of $0 is $3.94/MWh (line 11).

Q. How does WPS Corp propose to apply the proposed power supply cost recovery factor?

A. The Company proposes to apply a monthly PSCR factor of up to 3.94 mills per kilowatt-hour to Michigan retail sales for each month of the plan year of 2013.

Q. Could you please describe the sources of the net system requirements shown on line 2 of page 1 of Exhibit A-1 (JGG-1)?

A. Net system requirements were premised on historical requirement sales data that are corrected for weather and for known deviations. Some of the known deviations are determined after a field survey of WPS Corp's largest retail industrial customers and all firm wholesale customers. The electric residential category, which represents 21.5% of the total firm and interruptible sales, includes urban and rural residential and farm customers. The residential group forecast is based upon projected customer additions, the effective annual average number of customers, days covered by the meter reading year, and kilowatt-hour consumption per customer per meter reading day. Commercial and industrial classes have been combined, and these classes represent 58.1% of WPS Corp’s firm and interruptible sales. The 2013 sales forecast incorporates estimates by account executives based on personal interviews with WPS Corp's largest industrial customers representing 29.4% of the Company’s firm and interruptible sales. The wholesale requirement customer sales forecasts were provided by the wholesale customers, and represent 20.4% of the Company’s firm and interruptible sales. WPS Corp’s Michigan retail sales represent about 2.1% of its total requirement sales and as a result the current Michigan Energy Optimization initiative for energy efficiency is not expected to have significant impacts on its overall requirement sales.

Q. How are these net system requirements translated into the costs shown on page 2 of Exhibit A-1 (JGG-1)?

A. Net system sales requirements are increased for losses and company use to determine the total system requirements. From the total system requirements, average hydro, wind and contracted purchased power are subtracted and the remaining requirements are loaded on generating units via computer economic dispatch. This economic dispatch recognizes planned maintenance, unit heat rate, fuel cost, unit restrictions including environmental restrictions, and considers potential opportunity sales and purchases from the Midwest Independent Transmission System Operator ("MISO") Energy Market based on availability and projected market prices. Based on the level of operation of each generating unit, the amount of fuel burned and the cost of the fuel burned, the fuel expenses are determined. Combining the contracted purchased power costs, the opportunity purchases resulting from projected market prices, and forecasted MISO Energy Market charges, the purchased power expenses are determined. Opportunity sales revenues are based on the economic dispatch model and the projected market prices. The 2013 dispatch of the power supply resources and the related costs are shown on page 4 of Exhibit A-1 (JGG-1).

Q. Could you provide a brief description of the WPS Corp generation portfolio?

A. Yes. Presently, WPS Corp has generating facilities with a current capacity of approximately 2,112.5 MW. WPS Corp owns and operates 8 coal fired units with a total capacity of 1,178.8 MW and jointly owns 3 coal fired units with a WPS Corp assigned capacity of 429.0 MW that are operated by Wisconsin Power and Light Company. WPS Corp also has 454.1 MW of simple cycle gas-fired combustion turbines, 40.0 MW of hydro generation and approximately 10.6 MW (108 MW nameplate capacity) of wind generation.

Q. Are there any significant environmental regulatory issues that could impact power supply costs for 2013?

A. Yes. On July 11, 2011, the Cross State Air Pollution Rule ("CSAPR") was issued as final by the EPA. Subsequently on December 30, 2011 the U.S. Court of Appeals for the District of Columbia issued an order staying implementation of the CSAPR, and on August 21, 2012, the District of Columbia Circuit Court vacated the CSAPR. Since the CSAPR has been vacated, it is not expected to have any cost impacts in the 2013 PSCR Plan. However, if the EPA were to request a review of the decision by the entire DC Circuit Court and if the Court were to reverse its decision, power supply costs for WPS Corp in 2013 could be impacted.

Q. Have costs for chemicals used to reduce emissions been included in the 2013 PSCR Plan?

A. Yes. As approved in the December 4, 2007 Opinion and Order adopting settlement agreement issued in MPSC Case No. U-15352, the Company has included costs for chemicals used to reduce emissions in the 2013 PSCR Plan. The fuel costs shown on page 4 of Exhibit A-1 (JGG-1) include costs of $3.6 million for lime, ammonia, urea, calcium bromide, ATI and activated carbon sorbent. These chemicals act as reagents to remove/reduce emissions from the combustion by-products of burning coal. The use of lime in the Flue Gas Desulfurization system reduces SO_2 emissions. The use of ammonia and urea reduces NO_X emissions. The use of activated carbon sorbent, ATI and calcium bromide reduces Mercury emissions.

Q. Have costs for emission allowances been included in the 2013 PSCR Plan?

A. Yes. As also approved in MPSC Case No. U-15352, the Company has included costs for emission allowances in the 2013 PSCR Plan. The emission allowance costs for 2013 are forecasted to be $2.5 million as shown on page 4, line 25 of Exhibit A-1 (JGG-1).

Q. Has the Company included any outages in the 2013 PSCR Plan related to the Weston 4 excessive exfoliation and oxidation issue?

A. Yes. The Company has included in the 2013 PSCR Plan, two, 4-day outages of the Weston 4 Unit to manage the exfoliation issue in 2013. The issue of excessive exfoliation and oxidation at Weston 4 has been discussed in previous PSCR filings. The 2013 outages for the exfoliation process are planned to occur over weekends in order to limit the number of on peak hours that Weston 4 is not available, thus reducing the impact of replacement power costs resulting from the outages. In addition, on an actual basis, if the unit is forced out of service or if there is a planned outage for other reasons, the exfoliation process would be addressed during that outage if possible, avoiding additional outage time related to exfoliation.

Q. Does WPS Corp have the potential to incur coal and rail transportation contract obligation costs related to not meeting minimum amounts required to be purchased and transported under its coal and rail contracts?

A. Yes. If WPS Corp's use of coal falls below the minimum amounts required to be purchased and transported under its coal and rail contracts, WPS Corp is subject to contractual obligation costs. WPS Corp does have the potential to incur coal and rail transportation contract obligation costs in 2013. Due to the extremely low prices for natural gas and the associated impact to market prices, WPS Corp expects MISO to dispatch its coal-fired generation in 2013 less than in the past and therefore expects to use less coal than it previously forecasted at the time it entered into the current coal and rail contracts.

Q. Has WPS Corp included any coal or rail contract obligation costs in its 2013 PSCR Plan?

A. Yes. WPS Corp has included an estimate of $3.8 million of fuel expense related to rail contract obligation costs in its 2013 PSCR Plan. WPS Corp does not expect to incur coal contract obligation costs in 2013 at this time, and therefore has not included any of these costs. However, WPS Corp requests cost recovery through the PSCR mechanism for any coal and rail contract obligation costs.

Q. How did WPS Corp determine that it would be subject to the rail contract obligation costs?

A. WPS Corp did an hourly economic dispatch of its coal and gas fired generation, and purchased power sources to attempt to model the MISO market impact on WPS Corp's generation dispatch. Considering the contract obligation is a fixed cost, WPS Corp lowered the coal-fired dispatch price to reflect the contract obligation. This sends the correct economic signal of the true dispatch cost of WPS Corp's coal units which allows MISO to dispatch all units in its system on a least cost basis providing the lowest cost energy alternative to its customers. Based on the resulting dispatch, even with the lower dispatch price, the level of coal-fired generation did not meet the minimum coal transport requirements, indicating that paying the rail contract obligation costs and purchasing or generating from lower cost sources is the lower cost option for the WPS Corp customers. The dispatch model indicated that the amount of coal purchased did meet the minimum coal contract obligation.

Q. Could you please provide a general overview of the Company's purchased power agreements ("PPAs"), included in the 2013 plan, that are in excess of 6 months?

A. Yes.

Fox Energy Center – 500 MW of capacity from the 2 x 1 combined cycle facility; 759,763 MWh of energy, at an approximate total cost of $76,114,486. Capacity charges were approved in Case No. U-14422.

WRPC Hydro Generation – 20 MW of capacity; at an approximate cost of $314,823. Capacity charges were approved in Case No. U-14422.

Dominion Energy Kewaunee, Inc. - 340 MW of capacity; 2,850,157 MWh of energy, at an approximate total cost of $112,476,539. Capacity charges were approved in Case No. U-14040.

Manitoba Hydro – 100 MW of energy, 402,900 MWh of energy, at an approximate total cost of $15,120,416. WPS Corp is settling the energy provided by this agreement through the MISO Energy Market. There are no capacity charges with this agreement**.** There are Renewable Energy Credits associated with wind energy that are purchased as part of this agreement at a cost of $289,080.

WRPC (J31 Combustion Turbine) – 7.5 MW of capacity, at an approximate cost of $600,084; Capacity charges were approved in Case No. U-16882.

Forward Energy (Wind) – Project is expected to produce 159,673 MWh of energy at an approximate cost of $11,185,860. There are no capacity charges with this agreement**.**

Shirley Wind (Wind) – Project is expected to produce 65,873 MWh of energy at an approximate cost of $4,430,874. There are no specific capacity charges for this PPA. In addition, the price paid for the energy from this wind project that is above the MISO Locational Marginal Price ("LMP"), plus administrative costs, is reimbursed by the Department of Administration for the state of Wisconsin to meet its renewable energy requirements, which keeps WPS Corp economically whole.

Ameren Energy Marketing PPA1 - 25 MW energy purchase for a 24x7 energy product with the delivery point at WPS Corp's commercial pricing node; 219,000 MWhs of energy at a price of $28.40/MWh for a total cost of about $6,2 million. There are no capacity charges with this agreement**.**

Ameren Energy Marketing PPA2 - 25 MW energy purchase for a 24x7 energy product with the delivery point at WPS Corp's commercial pricing node; 219,000 MWhs of energy at a price of $27.60/MWh for a total cost of about $6.1 million. There are no capacity charges with this agreement**.**

Q. Has WPS Corp included any renewable energy costs in its PSCR plan for 2013?

A. Yes. As indicated in the previous discussion on purchased power contracts, WPS Corp has included purchased power costs for renewable energy purchases. Under Wisconsin state statute 196.378, WPS Corp is required to provide a portion of its electric power supply to retail customers from renewable energy sources. The PSCW has reviewed renewable energy sources as part of its audit in Docket No. 6690-UR-121 and has allowed these costs to be recovered in WPS Corp's Wisconsin rates for 2013. At this point in time, WPS Corp is not aware of any PSCW staff issues associated with renewable energy costs.

On October 6, 2008, Governor Jennifer M. Granholm signed into law the Clean, Renewable, and Efficient Energy Act, 2008 Public Act 295 (PA 295). Generally, PA 295 requires all electric providers serving retail load in Michigan to achieve a renewable energy credit standard. WPS Corp expects to meet the Michigan renewable energy requirements based on its current renewable energy portfolio and its future renewable energy plans. These requirements are addressed in separate proceedings before the MPSC.

Q. Has all of the opportunity sales revenue been included as a reduction to the power supply costs in this case?

A. Yes. All forecasted opportunity sales revenues have been included as a reduction to the power supply costs in this case; actual revenues will be considered in the reconciliation of this plan.

Q. What MISO Energy Market costs has the Company included in the 2013 PSCR Plan?

A. In addition to the normal opportunity sales and opportunity purchases that are expected to occur in the MISO Energy Market, the Company has included net cost increases for net marginal congestion costs of $1,000,000, net marginal loss costs of $3,514,105, Revenue Sufficiency Guarantee ("RSG") Make Whole Payment credits of $2,334,132, RSG charges of $1,284,274, Real Time Revenue Neutrality Uplift ("RNU") charges of

$2,820,493, Ancillary Services Market ("ASM") charges of $1,627,311, ASM credits of $1,127,601, Balancing Authority charges (MISO Schedule 24) of $300,720, MISO administrative charges for the Financial Transmission Rights ("FTRs") market (MISO Schedule 16) of $133,584 and MISO administrative charges for the Energy Market (MISO Schedule 17) of $2,088,909 in the 2013 PSCR Plan.

The Company also has the option of offering virtual generation and bidding virtual load into the MISO Energy Market. These risk management tools can be used to manage overall market price impacts to the Company and its customers. There are no costs or benefits included in the 2013 PSCR Plan for virtual offers and virtual bids, since these activities would be transacted dependent upon the circumstances of generation unit and transmission system availability and system load requirements as they occur on an actual basis in the Company's load zone, but if incurred, these costs and/or benefits will be reflected in the 2013 PSCR reconciliation.

MISO Energy Market costs are pursuant to FERC approved charges and the Company requests the inclusion of these costs and benefits in its PSCR mechanism.

Q. In what FERC Accounts are MISO Energy Market costs and credits being recorded?

A. Consistent with the FERC Order 668, MISO Schedules 16 and 17 for the MISO Energy Market costs are being recorded in FERC Account 575.7 (Market Administration, Monitoring and Compliance Services). Opportunity sales and ASM revenues from the MISO Energy Market are being recorded in FERC Account 447 (Sales for Resale). All other MISO Energy Market costs and credits are being recorded in FERC Account 555 (Purchased Power).

Q. Will the Company use any financial instruments to hedge fuel and purchased power costs in the 2013 PSCR plan?

A. Yes. In order to mitigate some of the effects of congestion pricing, utilities are allocated Auction Revenue Rights ("ARRs") which provide revenues that can either be retained or used in the purchase of FTRs to hedge future potential congestion costs. Revenues from ARRs and credits or charges from the MISO Market for FTRs can be used to offset some of the effects of the higher or lower prices that will be reflected in the LMPs due to congestion. The FTRs are considered financial instruments, since they represent future rights to offset congestion costs. The Company has received ARRs and has purchased FTRs to manage its congestion cost risks.

With the volatility of natural gas prices, the Company has also utilized NYMEX-traded natural gas futures and options contracts to manage or hedge some portion of the price risk of natural gas used in its supply resource mix (e.g., gas-fired generation and purchased power). A credit of ($32,800) has been included in the 2013 PSCR Plan as part of purchased power costs for gas hedge impacts in 2013 based on the market price of natural gas at the time this fuel and purchased power forecast was prepared.

In addition to hedging the risk of natural gas in the supply portfolio, WPS Corp also has a hedging program to manage the fuel cost risk associated with the delivery of coal resulting from diesel fuel surcharges which are based on a published diesel fuel price index. The diesel fuel index (EIA On-Highway Diesel, All Types) used to set the surcharge by the rail company is not forward traded; however, NYMEX Heating Oil prices are closely correlated with the EIA Diesel price and are traded in very liquid markets. Therefore the Company hedges these coal transportation surcharges with the purchase of NYMEX-traded Heating Oil futures and options contracts to manage or hedge a portion of the price risk of coal transportation costs.

The Company requests the inclusion of costs and credits in the PSCR for FTRs and the impacts from the use of natural gas and heating oil futures and options contracts for the purpose of hedging fuel and purchased power costs.

Q. Do the power supply costs you are proposing include charges for network transmission service from the American Transmission Company LLC ("ATCLLC") and the MISO and their related administrative charges for transmission service?

A. Yes. WPS Corp receives transmission and related services from the ATCLLC and MISO at FERC approved rates. As approved in Case No. U-13688, WPS Corp's ATCLLC and MISO transmission network and related administrative costs have been included in PSCR costs since the 2005 PSCR Plan. For the total WPS Corp system in 2013, the forecasted cost for these services is approximately $120,489,000.

These costs are included in the line titled "Transmission – PSCR Recovery" on page 2, line 13 of Exhibit A-1 (JGG-1) in which the system costs are developed.

Q. In what FERC Accounts are ATCLLC and MISO network transmission and their related administrative charges recorded?

A. ATCLLC and MISO network transmission charges are recorded in FERC Account 565 (Transmission of Electricity by Others). Consistent with the FERC Order 668, MISO Schedule 10 costs are recorded in FERC Accounts 561.4 (Scheduling, System Control and Dispatching Services), 561.8 (Reliability Planning and Standards Development Services) and 575.7 (Market Administration, Monitoring and Compliance Services).

Q. Are there any MISO market changes from 2012 that could impact WPS Corp power supply costs in 2013?

A. Yes. In 2012 there were two notable changes in the market that impacted, or could impact WPS Corp. These include the changes in Resource Adequacy and the Voltage and Local Reliability (VLR) cost allocation changes.

Q. What are the proposed changes in Resource Adequacy and how will this impact UPPCO?

A. Currently, MISO evaluates the ability of load serving entities (LSEs) to meet their load on a monthly basis. To meet the requirements of the current construct, WPS Corp was required to demonstrate that it had generation or purchased power contracts in place to meet its forecasted non-coincident monthly peak load. Beginning with the 2013/14 planning year on June 1, 2013, MISO has moved to an annual capacity construct. Now, instead of demonstrating monthly compliance, each LSE will provide an annual coincident peak forecast to MISO and then be required to demonstrate the ability to meet this load. This change could impact WPS Corp's resource requirements and resulting power supply costs.

Q. Please describe the Voltage and Local Reliability ("VLR") cost allocation changes and the impact that this could have on WPS Corp.

A. The re-dispatch of generation occurs each day as MISO operates the system in a reliable manner. This re-dispatch is often for reasons of reliability, not economics, so the generators' cost may not be met by energy prices. In this circumstance, Revenue Sufficiency Guarantee ("RSG") payments are made to keep the generator owner whole. RSG payments fall into one of three categories; (1) Constraint Management (paid by all of MISO), (2) Day Ahead Deviation (paid by entities that withdrew more energy than planned in the Day Ahead market), and (3) Non-identifiable (paid by all of MISO). VLR issues have been part of the constraint management portion of RSG and the costs were spread out over MISO on a load ratio share basis. MISO has determined that VLR costs are caused by local operating difficulties, and should be paid by the market participants who are directly affected. WPS Corp participated in MISO's FERC filing by intervening and submitting comments to protect WPS Corp's interests. The filing was approved by FERC and went into effect on September 2, 2012. The impact to WPS Corp is not known at this time, but the situation will be monitored and WPS Corp will work to ensure that costs are allocated in an equitable manner.

Q. Pages 2 and 3 of the Staff Additional Filing Requirements request an explanation of the differences between the then actual year to date and the Forecasted Power Supply Costs year to date. Can you please explain the differences between actual 2012 and forecasted 2013?

A. Yes. The following describes and quantifies the major reasons for the differences between the year-to-date actual through July 2012 and forecasted year-to-date through July 2013 power supply costs (WPS Corp's submittal of this information should not imply that the Company agrees that this comparison is relevant to the proposed 2013 plan.):

<u>Fossil</u>

-Generation (MWh): As illustrated on Page 5 of Exhibit A-1 (JGG-1), the forecasted 2013 fossil generation volumes are expected to increase by approximately 28% as compared to 2012. The increase is primarily the result of less planned maintenance outages in 2013 than actually occurred in 2012, and higher natural gas prices of approximately 12% with resulting market price impacts on the generation of the units. Additional specific generation changes are identified below within each plant's generation discussion.

Pulliam

-Generation (MWh): The MWhs for Pulliam are projected to increase in 2013 compared to 2012 mainly due to market conditions described above. In addition, the MWhs for Pulliam also reflect a planned maintenance outage totaling 8 weeks at Pulliam unit 6 in 2013 versus an actual maintenance outage at Pulliam unit 7 in 2012 totaling 4 weeks.

-Costs ($/MWh): The $/MWh cost is lower in the 2013 plan than in 2012 due to several factors:

(1) Reduced MWh generation at Pulliam 5-6 units and increased MWh generation at Pulliam 7-8 in 2013 causing the heat rate to be lower and resulting in a lower cost per MWh of $2.23/MWh,

(2) Increased average coal and rail contract costs resulting in an increase of $1.63/MWh,

(3) The 2013 plan is lower than 2012 due to lower contract obligation costs of $4.06/MWh resulting from increased tons burned; and

(4) The 2013 plan is lower because the 2012 actuals include a semi-annual inventory adjustment of $2.03/MWh.

Weston

-Generation (MWh): The MWhs for Weston are projected to increase in 2013 compared to 2012 mainly due to market conditions described above. In addition, there are no planned maintenance outages scheduled in the 2013 plan versus maintenance outages in 2012 on Weston unit 1 of 1 week and Weston unit 4 of 5 weeks.

Columbia

-Generation (MWh): The MWhs for Columbia are projected to increase in 2013 compared to 2012 due to 4 weeks of a planned maintenance outage at Columbia 1 and 4 weeks of a planned maintenance outage at Columbia 2 in 2013 versus maintenance outages in 2012 for Columbia 1 and Columbia 2 of 5 weeks each.

Edgewater

-Generation (MWh): The MWhs for Edgewater are projected to increase in 2013 compared to 2012 due to a planned maintenance outage in 2013 of 2 weeks versus 8 weeks in 2012.

Emission Allowances Costs

-The 2013 PSCR plan emission allowance costs are 7.17% or $99,000 higher than 2012 mainly due to higher generation of fossil units resulting in the expensing of more allowances .

Hydro

-Generation (MWh): The hydro generation is variable based upon water flows. The hydro generation was lower than normal in 2012 due to lower than expected snow melt and rainfall. The 2013 PSCR plan reflects expected hydro generation under normal conditions utilizing a 30-year average.

Peakers

-The Company's gas fired combustion turbine generation is highly variable and is affected by baseload unit outage schedules, market conditions and peak demands.

Purchased Power

As illustrated on Page 5 of Exhibit A-1 (JGG-1), the forecasted 2013 purchased power volumes are expected to decrease in excess of 32% as compared to 2012 actuals. The decrease is the result of lower forecasted system requirements, increased coal-fired generation and lower forecasted opportunity sales. The higher average cost per MWh for purchased power costs for 2013 are primarily the result of increases in the forecasted market prices for energy from 2012. The 2012 purchased power prices were significantly lower due to the unprecedented low prices for natural gas used as fuel for generation supplying purchased power. The natural gas prices for 2013 are expected to be higher, as market suppliers adjust their production to reduce over-supply and more normal weather and more typical demand is forecasted.

Transmission Expenses

Transmission expenses are expected to increase from 2012 to 2013 by 8.7% due to increased FERC approved rates by the ATCLLC and MISO for network transmission services. This increase reflects the on-going construction costs for upgrades to the ATCLLC transmission network as well as increases from Regional Expansion Criteria and Benefits ("RECB") cost sharing and Multi-Value Project ("MVP") projects. RECB cost sharing is included in MISO's FERC-approved transmission tariff and imposes socialized cost sharing for MISO Market Participants within a region for a portion of new transmission construction of 345 KV or higher voltages. MVPs are transmission projects deemed by Midwest ISO to benefit, collectively, all participants in the Midwest ISO market. For this reason, MVP costs are socialized across the Midwest ISO footprint.

Opportunity Sales

As illustrated on Page 5 of Exhibit A-1 (JGG-1), the forecasted opportunity sales volumes for the 2013 plan year are expected to decrease compared to year 2012. Opportunity sales volumes are closely related to the availability of excess hourly generation at market clearing prices, forecasted demand and forecasted market prices, all of which are taken into consideration through the production cost modeling process employed by WPS Corp.

Opportunity sales are comprised of both short (spot) energy/capacity/ASM sales and mid-term (Firm) energy/capacity sales. The higher MWh volume in 2012 was primarily the result of increased demand in the MISO market due to record setting temperatures in June and July across the MISO footprint. In 2013, the production cost model is showing a decrease in the volume of energy sales to the MISO due to the forecast of more normal weather patterns.

<u>Interruptible Buyout</u>

WPS Corp forecasted no interruptible buyouts in the 2013 PSCR Plan, since any revenue collected for buyouts is used to offset the higher cost of energy.

Q. Are there any significant reasons, such as new power sources or major outages that would require a recalculation of 2013 plan costs for a "same basis" comparison with 2012 actual costs as requested in item 4 of the Additional Filing Requirements?

A. No.

Q. The PSCR plan filing requirements of 1982 PA 304 contain additional requirements that you have not addressed. Please explain.

A. The Commission's August 1, 1984 Opinion and Order implementing the PSCR plan for 1984, issued in Case No. U-7805, exempted WPS Corp from any further filings of five-year forecasts and underlying information concerning fuel contracts and power supply arrangement as required by Section 6j(3) and 6j(4) of Act 304. Therefore, I have not addressed those matters.

Q. Please discuss the actions of the PSCW that are relevant to the 2013 PSCR plan.

A. WPS Corp's electric system is integrated and its power supply costs are incurred on a system wide basis. There are no separate power supply costs incurred specifically for the Michigan jurisdictional sales. Because power supply costs are incurred on a system wide basis, all of the contracts underlying these costs are monitored in depth on a continuous basis by the PSCW.

Q. Mr. Guntlisbergen, regarding the proposed 2013 PSCR factors, are you saying that the PSCW reviews and approves the major contracts and power supply arrangements underlying those factors?

A. Yes. In May of 2012, WPS Corp filed a 2013 test year rate case with the PSCW, under Docket No. 6690-UR-121. An initial staff audit of fuel and purchased power expenses was completed, however the PSCW will not make a formal ruling until later this year.

Q. So that the MPSC is assured that this review is already being performed by the PSCW, would you please describe the monitoring activities being conducted by the PSCW?

A. The PSCW review process evaluates the reasonableness and prudence of power supply to ensure adequate future service is supplied at minimal cost and minimal environmental impact. Because of the ongoing nature of the process, there is sufficient assurance that appropriate decisions have been previously made to cover power supply arrangements for the immediate upcoming 12-month period.

Q. What plans or procedures are in place for the State of Wisconsin and the PSCW for the authorization of new generation facilities?

A. The 1997 Wisconsin Act 204 ("ACT") became law in the spring of 1998. The ACT encompasses the Governor's electric reliability plan and in particular contains provisions which relate to the planning and approval by the PSCW of electric power generation and transmission facilities, the regional management of the transmission system, and new electric power generation, including the ownership and operation of wholesale merchant plants, among other things. The ACT replaced the previous planning process called the Advance Plan with a process called Strategic Energy Assessment.

As a replacement for the Advance Plan, the ACT requires the PSCW to prepare a biennial strategic energy assessment that evaluates the adequacy and reliability of the state's current and future electrical supply. The assessment is to include, among other things, identification of and description of projected demand for electric energy, the basis for determining such demand, and whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The ACT also modified the facility certification process by which licenses are granted for the construction of power plants and transmission lines. This ACT became effective September 1, 1998.

Rulemaking proceedings to establish procedures and requirements for reporting information to the PSCW to enable it to prepare strategic energy assessments were completed in 1999.

The ACT also modified the Certificate of Public Convenience and Necessity requirements by limiting its applicability to generation and transmission facilities.

Q. Does the ACT have any effect on the 2013 PSCR Plan?

A. No.

Q. Does WPS Corp have adequate capacity at this time for year 2013?

A. Yes.

Q. Please explain the procedures that WPS Corp follows to minimize the cost of fuel.

A. The following describes the processes that help to minimize the costs of fuel and purchased power:

Within WPS Corp's Fuel Services Department, which is directly responsible for fuel procurement, policies and procedures have been developed to outline a series of rules and directives by which to conduct the fuel procurement operations. The procedures and policies include:

1. Selection of a vendor through a competitive bid process;
2. Test burning of new coals at the facility to assure plant compatibility; and
3. The use of a bid security system to ensure fair competition.

Q. Do the amounts of projected power supply costs include any items of cost that the Commission could reasonably anticipate disallowing under section 6j(13)?

A. No.

Q. What is your evaluation of the reasonableness and prudence of the proposed 2013 PSCR plan?

A. I believe that WPS Corp's PSCR plan is reasonable and prudent. I base this conclusion not only on my knowledge of WPS Corp's actions, but also on the actions of the PSCW. The proposed increase in the authorized PSCR factor from 2012 of $2.78/Mwh to $3.94/Mwh in 2013 is primarily the result of forecasted higher natural gas prices, and increases in the ATCLLC and MISO transmission charges as discussed previously.

Q. Does that conclude your direct testimony?

A. Yes, it does.

WISCONSIN PUBLIC SERVICE CORPORATION

DEVELOPMENT OF 2013 POWER SUPPLY COST RECOVERY FACTORS

N.S.R. METHOD WITH ANNUAL LOSS FACTORS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
1. Total System Costs for Recovery (000's of $)	$51,446	$48,783	$50,400	$47,255	$47,232	$50,557	$54,303	$53,497	$49,690	$47,842	$48,243	$49,049	$598,297
* 2. Net System Requirements MWh	1,164,537	1,085,842	1,129,318	1,045,261	1,069,569	1,148,054	1,209,809	1,188,207	1,102,887	1,065,462	1,070,436	1,123,249	13,402,631
3. Average Power Supply Costs $/MWh	$44.18	$44.93	$44.63	$45.21	$44.16	$44.04	$44.89	$45.02	$45.05	$44.90	$45.07	$43.67	$44.64
4. Estimated 2013 Michigan Retail Sales MWh	23,229	23,914	24,548	23,366	21,851	23,908	25,542	25,727	23,190	24,190	23,641	24,582	287,688
** 5. Michigan Retail Power Supply Costs (000's of $)	$1,026	$1,074	$1,096	$1,056	$965	$1,053	$1,147	$1,158	$1,045	$1,086	$1,065	$1,073	$12,842
6. Michigan Power Supply Cost Rate ($/MWh)	$44.18	$44.93	$44.63	$45.21	$44.16	$44.04	$44.89	$45.02	$45.05	$44.90	$45.07	$43.67	$44.64
7. Base Power Supply Costs $/MWh	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70	$40.70
8. 2013 PSCR Factor $/MWh	$3.48	$4.23	$3.93	$4.51	$3.46	$3.34	$4.19	$4.32	$4.35	$4.20	$4.37	$2.97	$3.94
9. 2012 Over/Under-recovery (000's of $)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10. PSCR Rate for 2012 Over/Under-recovery ($/MWh)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11. 2013 PSCR Factor + PSCR Rate for 2012 Over/Under-recovery ($/MWh)	$3.48	$4.23	$3.93	$4.51	$3.46	$3.34	$4.19	$4.32	$4.35	$4.20	$4.37	$2.97	$3.94

* - Total Generation and Purchases Less Losses, Opportunity Sales, GDS and Company Use
** - Average Power Supply Costs ($/MWh) times Estimated Michigan Retail Sales (MWh)

WISCONSIN PUBLIC SERVICE CORPORATION

ANTICIPATED SOURCES AND COSTS OF POWER SUPPLY

FOR DEVELOPMENT OF 2013 POWER SUPPLY COST RECOVERY FACTORS

Units: 000's of $

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	System costs for Recovery													
2														
3	Fossil Fuel*	19,993	18,457	18,607	16,572	17,907	17,682	22,299	19,680	18,195	14,017	17,435	21,865	222,709
4														
5	Emission Allowances Costs	235	211	209	163	195	204	263	224	214	153	197	252	2,520
6														
7	Combustion Turbines	1,454	716	266	94	163	457	868	711	271	86	452	686	6,224
8														
9	Purchased Power	23,817	22,058	24,033	26,233	27,028	25,463	23,408	25,973	24,543	25,863	23,120	19,970	291,509
10														
11	Contract Buyout Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
12														
13	Transmission - PSCR Recovery	10,088	9,845	9,954	9,834	9,985	10,181	10,406	10,309	10,101	9,855	9,901	10,030	120,489
14														
15	Less: Opportunity Sales -													
16	Resale and Retail	-4,141	-2,504	-2,669	-5,641	-8,046	-3,430	-2,941	-3,400	-3,634	-2,132	-2,862	-3,754	-45,154
17														
18	TOTAL System Costs for Recovery	51,446	48,783	50,400	47,255	47,232	50,557	54,303	53,497	49,690	47,842	48,243	49,049	598,297

* Fossil Fuel Expense excluding unit train costs, handling and demurrage.

QUESTION (1)

2012 Year-to-Date Actual P.S.C.R. Costs ($/MWh)

				JAN	FEB	MAR	APR	MAY	JUN	JUL	Year To Date Through July
1	Fossil Generation (MWh)		Pulliam	27,520	25,151	6,619	18,872	79,111	64,188	120,156	341,617
2			Weston	72,286	61,935	46,012	117,180	227,636	183,849	268,160	977,058
3			Weston 4	225,178	210,196	221,022	137,268	25,178	227,524	248,062	1,294,428
4			Edgewater	41,711	51,626	48,555	102	-	26,204	61,706	229,904
5			Columbia	145,753	128,722	112,321	188,286	222,001	209,832	217,701	1,224,616
6		Total Generation		512,448	477,630	434,529	461,708	553,926	711,597	915,785	4,067,623
7											
8	Fossil Costs ($000's)		Pulliam	1,050	878	230	681	4,335	1,703	4,255	13,132
9			Weston	2,342	1,849	1,424	3,134	7,549	5,562	8,181	30,041
10			Weston 4	5,900	5,240	5,724	3,567	721	4,616	6,630	32,398
11			Edgewater	1,088	1,360	1,259	13	8	737	1,666	6,131
12			Columbia	2,659	2,409	2,116	3,240	3,764	3,642	3,765	21,595
13		Total Costs		13,039	11,736	10,753	10,635	16,377	16,260	24,497	103,297
14											
15											
16		Costs $/MWh	Pulliam	38.15	34.91	34.75	36.09	54.80	26.53	35.41	38.44
17			Weston	32.40	29.85	30.95	26.75	33.16	30.25	30.51	30.75
18			Weston 4	26.20	24.93	25.90	25.99	28.64	20.29	26.73	25.03
19			Edgewater	26.08	26.34	25.93	127.45	0.00	28.13	27.00	26.67
20			Columbia	18.24	18.71	18.84	17.21	16.95	17.36	17.29	17.63
21		Average Costs/MWh		25.44	24.57	24.75	23.03	29.57	22.85	26.75	25.39
22											
23	Emission Allowances	Costs		145	123	104	167	264	245	333	1,381
24											
25	Hydro	Generation (MWh)		15,860	14,417	28,341	15,092	20,253	14,703	14,638	123,304
26		Costs		---	---	---	---	---	---	---	---
27		Costs $/MWh		---	---	---	---	---	---	---	---
28											
29	Peakers	Generation (MWh)		1,055	728	153	627	5,782	11,780	61,965	82,090
30		Costs ($000's)		152	134	100	116	330	578	2,886	4,296
31		Costs $/MWh		144.08	184.07	653.59	185.01	57.07	49.07	46.57	52.33
32											
33	Wind	Generation (MWh)		38,170	28,168	38,101	33,760	32,045	25,277	13,480	209,001
34											
35	Purchased Power & Regulation	MWh		756,795	750,375	712,478	649,373	710,956	744,571	813,097	5,137,645
36		Costs ($000's)		30,054	28,588	28,182	27,171	29,876	28,787	33,192	205,850
37		Costs $/MWh		39.71	38.10	39.55	41.84	42.02	38.66	40.82	40.07
38											
39	Transmission Expenses (Network)	Costs ($000's)		9,236	9,084	9,134	9,050	9,203	9,421	9,571	64,699
40											
41	Less: Opportunity Sales (Mwh)			-92,858	-131,525	-47,437	-61,809	-158,400	-230,733	-376,768	-1,099,530
42	Less: Opportunity Sales ($000's)			-3,197	-4,139	-1,883	-2,210	-5,422	-7,576	-15,827	-40,254
43		Costs $/MWh		34.43	31.47	39.69	35.76	34.23	32.83	42.01	36.61
44											
45	Less: Interruptible Buyout Sales (Mwh)			0	0	0	0	0	-1,628	-10,596	-12,224
46	Less: Interruptible Buyout Revenue			0	8	0	0	0	-94	-1,014	-1,100
47											
48	TOTAL	System Requirements		1,231,470	1,139,793	1,166,165	1,098,751	1,164,562	1,275,567	1,431,601	8,507,909
49		Costs ($000's)		49,429	45,534	46,390	44,929	50,628	47,621	53,638	338,169
50		Costs $/MWh		40.14	39.95	39.78	40.89	43.47	37.33	37.47	39.75

QUESTION (1)

2013 Plan PSCR Costs ($/MWh)

			JAN	FEB	MAR	APR	MAY	JUN	JUL	Year to date Through July	Aug	Sep	Oct	Nov	Dec	Total
1	Fossil	Generation (MWh)														
2		Pulliam	75,388	94,987	80,827	13,769	4,579	28,194	93,901	391,645	46,619	47,322	55,194	65,282	94,256	700,318
3		Weston	217,196	213,247	231,291	210,502	210,449	203,297	247,492	1,533,474	218,009	205,541	30,313	122,532	234,560	2,344,429
4		Weston 4	240,041	224,413	214,151	241,994	248,081	215,987	241,071	1,625,738	236,483	205,002	242,184	239,277	250,675	2,799,359
5		Edgewater	55,685	21,137	51,949	56,572	54,483	48,817	59,498	348,141	55,906	55,926	28,397	50,997	57,247	596,614
6		Columbia	218,359	176,302	136,847	125,489	206,499	212,146	221,109	1,296,751	218,692	211,646	220,923	212,203	218,685	2,378,900
7		Total Generation	806,669	730,086	715,065	648,326	724,091	708,441	863,071	5,195,749	775,709	725,437	577,011	690,291	855,423	8,819,620
8																
9		Costs ($000's) (Excluding Train, Handling, & Demurrage)(Including Emission Control Costs)														
10		Pulliam	2,289	2,788	2,516	512	236	969	3,084	12,394	1,555	1,547	1,854	2,300	3,048	22,698
11		Weston	6,298	6,278	6,764	6,130	6,179	5,992	7,370	45,011	6,502	6,124	1,171	3,801	6,954	69,563
12		Weston 4	6,060	5,694	5,501	6,233	6,414	5,681	6,340	41,923	6,243	5,370	6,326	6,257	6,480	72,599
13		Edgewater	1,480	584	1,403	1,466	1,435	1,283	1,542	9,193	1,472	1,447	729	1,321	1,482	15,644
14		Columbia	3,866	3,113	2,423	2,231	3,643	3,757	3,963	22,996	3,908	3,707	3,937	3,756	3,901	42,205
15		Total Costs	19,993	18,457	18,607	16,572	17,907	17,682	22,299	131,517	19,680	18,195	14,017	17,435	21,865	222,709
16																
17		Costs $/MWh														
18		Pulliam	30.36	29.35	31.13	37.18	51.54	34.37	32.84	31.65	33.36	32.69	33.59	35.23	32.34	32.41
19		Weston	29.00	29.44	29.24	29.12	29.36	29.47	29.78	29.35	29.82	29.79	38.63	31.02	29.65	29.67
20		Weston 4	25.25	25.37	25.69	25.76	25.85	26.30	26.30	25.79	26.40	26.19	26.12	26.15	25.85	25.93
21		Edgewater	26.58	27.63	27.01	25.91	26.34	26.28	25.92	26.41	26.33	25.87	25.67	25.90	25.89	26.22
22		Columbia	17.70	17.66	17.71	17.78	17.64	17.71	17.92	17.73	17.87	17.52	17.82	17.70	17.84	17.74
23		Average Costs/MWh	24.78	25.28	26.02	25.56	24.73	24.96	25.84	25.31	25.37	25.08	24.29	25.26	25.56	25.25
24																
25		Emission Allowances Costs	235	211	209	163	195	204	263	1,480	224	214	153	197	252	2,520
26																
27	Hydro	Generation (MWh)	21,279	19,366	24,247	30,399	28,803	23,847	20,306	168,247	17,519	18,864	22,404	23,525	22,827	273,386
28		Costs	---	---	---	---	---	---	---	---	---	---	---	---	---	---
29		Costs $/MWh	---	---	---	---	---	---	---	---	---	---	---	---	---	---
30																
31	Peakers	Generation (MWh)	14,850	12,846	3,416	0	1,364	7,123	15,331	54,930	12,270	3,398	7	6,665	10,659	87,929
32		Costs ($000's)	1,454	716	266	94	163	457	868	4,018	711	271	86	452	686	6,224
33		Costs $/MWh	97.9	55.7	77.9	0.0	119.5	64.2	56.6	73.2	58.0	79.8	12,285.7	67.8	64.4	70.8
34																
35	Wind	Generation (MWh)	36,332	31,703	33,452	34,744	32,352	22,321	16,430	207,334	12,400	18,405	27,505	30,204	34,850	330,698
36																
37	Purchased Power & Regulation															
38		MWh Purchases	467,663	418,509	492,438	553,321	575,419	538,980	438,459	3,484,789	518,430	493,570	557,518	457,461	364,325	5,876,093
39		Costs ($000's)	23,817	22,058	24,033	26,233	27,028	25,463	23,408	172,040	25,973	24,543	25,863	23,120	19,970	291,509
40		Costs $/MWh	50.9	52.7	48.8	47.4	47.0	47.2	53.4	49.4	50.1	49.7	46.4	50.5	54.8	49.6
41																
42	Contract Buyout Amortization:															
43		Costs ($000's)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44																
45	Transmission Expenses ($000's)		10,088	9,845	9,954	9,834	9,985	10,181	10,406	70,293	10,309	10,101	9,855	9,901	10,030	120,489
46																
47	Less: Opportunity Sales + RTMP (Mwh)		-120,426	-68,824	-79,342	-166,041	-235,893	-92,127	-80,012	-842,665	-85,430	-98,499	-62,658	-81,039	-105,267	-1,275,558
48		Opportunity Sales ($000's)	-4,141	-2,504	-2,669	-5,641	-8,046	-3,430	-2,941	-29,372	-3,400	-3,634	-2,132	-2,862	-3,754	-45,154
49		Costs/MWh	34.4	36.4	33.6	34.0	34.1	37.2	36.8	34.9	39.8	36.9	34.0	35.3	35.7	35.4
50																
51	TOTAL	System Requirements (MWh)	1,226,367	1,143,686	1,189,276	1,100,749	1,126,136	1,208,585	1,273,585	8,268,384	1,250,898	1,161,175	1,121,787	1,127,107	1,182,817	14,112,168
52		Costs ($000's)	51,446	48,783	50,400	47,255	47,232	50,557	54,303	349,976	53,497	49,690	47,842	48,243	49,049	598,297
53		Costs/MWh	42.0	42.7	42.4	42.9	41.9	41.8	42.6	42.3	42.8	42.8	42.7	42.8	41.5	42.4
54																
55	Less:	Losses (MWh)	-59,399	-55,394	-57,602	-53,314	-54,544	-58,537	-61,686	-400,476	-60,587	-56,241	-54,334	-54,591	-57,289	-683,518
56		Company Use (MWh)	-2,431	-2,450	-2,356	-2,174	-2,023	-1,994	-2,090	-15,518	-2,104	-2,047	-1,991	-2,080	-2,279	-26,019
57																
58	TOTAL	System Requirements less losses (MWh)	1,164,537	1,085,842	1,129,318	1,045,261	1,069,569	1,148,054	1,209,809	7,852,390	1,188,207	1,102,887	1,065,462	1,070,436	1,123,249	13,402,631

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Case No. U-17092
Exhibit A-1 (JGG-1)
Witness: J G Guntlisbergen
Date: 9/26/12

	QUESTION (1)		7 Months 2012 ACTUAL	7 Months 2013 PLAN	CHANGE	% CHANGE
1	Fossil	Generation (MWh)				
2		Pulliam	341,617	391,645	50,028	14.64%
3		Weston	2,271,486	3,159,212	887,726	39.08%
4		Edgewater	229,904	348,141	118,237	51.43%
5		Columbia	1,224,616	1,296,751	72,135	5.89%
6		Total Generation	4,067,623	5,195,749	1,128,126	27.73%
7						
8		Costs ($000's)				
9		Pulliam	13,132	12,394	-738	-5.62%
10		Weston	62,439	86,934	24,495	39.23%
11		Edgewater	6,131	9,193	3,062	49.94%
12		Columbia	21,595	22,996	1,401	6.49%
13		Total Costs	103,297	131,517	28,220	27.32%
14						
15		Costs $/MWh				
16		Pulliam	38.44	31.65	-6.79	-17.68%
17		Weston	27.49	27.52	0.03	0.11%
18		Edgewater	26.67	26.41	-0.26	-0.98%
19		Columbia	17.63	17.73	0.10	0.56%
20		Average Costs/MWh	25.39	25.31	-0.08	-0.32%
21						
22		Emission Allowances Costs	1,381.0	1,480.0	99	7.17%
23						
24	Hydro	Generation (MWh)	123,304	168,247	44,943	36.45%
25		Costs	---	---		---
26		Cost $/MWh	---	---		---
27						
28	Peakers	Generation (MWh)	82,090	54,930	-27,160	-33.09%
29		Costs ($000's)	4,296	4,018	-278	-6.47%
30		Costs $/MWh	52.33	73.15	21	39.77%
31						
32	Wind	Generation (MWh)	209,001	207,334	-1,667	-0.80%
33						
34	Purchased Power(incl Third Party)					
35		MWh Purchased	5,137,645	3,484,789	-1,652,856	-32.17%
36		Costs ($000's)	205,850	172,040	-33,810	-16.42%
37		Costs $/MWh	40.07	49.37	9.30	23.22%
38						
39	Transmission Expenses(Network) ($000's)		64,699	70,293	5,594	8.65%
40						
41	Less: Opportunity Sales (Mwh)		-1,099,530	-842,665	256,865	-23.36%
42		Costs ($000's)	-40,254	-29,372	10,882	-27.03%
43		Costs $/MWh	36.61	34.86	-1.75	-4.78%
44						
45	Less: Interruptible Buyout Sales (MWh)		-12,224	0.0	12,224	
46	Less: Interruptible Buyout Revenue ($000's)		-1,100	0.0	1,100	
47						
48	TOTAL	System Requirements (MWh)	8,507,909	8,268,384	-239,525	-2.82%
49		Costs ($000's)	338,169	349,976	11,807	3.49%
50		Costs $/MWh	39.75	42.33	2.58	6.49%

WISCONSIN PUBLIC SERVICE CORPORATION

SUMMARY OF 2012 OVER/UNDERRECOVERY OF POWER SUPPLY COSTS

Question (5)	Actual 2011 Balance	Actual 2012 JAN	Actual 2012 FEB	Actual 2012 MAR	Actual 2012 APR	Actual 2012 MAY	Actual 2012 JUN	Actual 2012 JUL	Actual 2012 AUG	Forecasted 2012 SEP	Forecasted 2012 OCT	Forecasted 2012 NOV	Forecasted 2012 DEC	Actual & Forecasted 2012 TOTAL
1 Total Requirement Sales (Mwhs)		1,198,198	1,099,147	1,124,213	1,056,568	1,125,972	1,231,087	1,385,595	1,176,473	1,164,469	1,173,188	1,119,501	1,209,439	14,063,850
2 Total System Power Supply Costs		$49,429,478	$45,533,929	$46,389,861	$44,928,949	$50,628,187	$47,621,089	$53,637,215	$51,353,840	$47,234,040	$46,753,735	$45,425,698	$47,940,375	$576,876,395
3 Cost/Kwh		$0.04125	$0.04143	$0.04126	$0.04252	$0.04496	$0.03868	$0.03871	$0.04365	$0.04056	$0.03985	$0.04058	$0.03964	$0.04102
4														
5 PSCR SALES (KWH)		22,936,654	23,246,725	23,953,470	21,905,272	23,101,116	23,305,728	25,852,507	25,543,824	21,709,000	23,846,000	22,873,000	24,618,000	282,891,296
6 PSCR Base Rate		$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	$0.04070	
7 Applied PSCR Factor ($/kwh)		$0.00557	$0.00557	$0.00278	$0.00150	-$0.00225	-$0.00248	-$0.00248	-$0.00248	-$0.00248	-$0.00144	-$0.00144	-$0.00144	
8														
9 TOTAL PSCR REVENUES ($'s)		$1,061,279	$1,060,257	1,034,956	$907,584	$886,742	$890,745	$988,083	$976,285	$829,718	$936,166	$897,967	$966,474	$11,436,254
10 APPLICABLE POWER COSTS ($'s)		$946,210	$963,033	$988,423	$931,488	$1,038,718	$901,516	$1,000,766	$1,115,005	$880,577	$950,307	$928,112	$975,821	$11,619,976
11														
12 Over/(Under) Recovery	$163,239	$115,069	$97,224	$46,533	($23,904)	($151,977)	($10,771)	($12,683)	(138,720)	(50,859)	(14,142)	(30,145)	(9,348)	(20,483)
13 $/KWH		0.00502	0.00418	0.00194	-0.00109	-0.00658	-0.00046	-0.00049	-0.00543	-0.00234	-0.00059	-0.00132	-0.00038	-0.00007
14														
15 Over/(Under) Recovery Balance	$163,239	$278,308	$375,532	$422,064	$398,160	$246,184	$235,413	$222,729	$84,010	$33,151	$19,009	($11,135)	($20,483)	
16														
17		10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	0.27%	0.27%	
18 Interest		$ 1,895	$ 2,806	$ 3,423	$ 3,520	$ 2,765	$ 2,067	$ 1,966	$ 1,316	$ 503	$ 224	$ 1	$ (4)	20,483
19 Interest Balance		$1,895	$4,701	$8,124	$11,644	$14,409	$16,476	$18,443	$19,759	$20,262	$20,486	$20,486	$20,483	
20														
21 Over/(Under) Recovery + Interest Balance	$163,239	$280,203	$380,233	$430,189	$409,804	$260,593	$251,889	$241,172	$103,768	$53,413	$39,495	$9,351	($0)	
22														

WISCONSIN PUBLIC SERVICE CORPORATION

MPSC Vol No 5-ELECTRIC — ____ Revised Sheet No. D-1.00
(2013 PSCR Plan Case No. U-17092) — Replaces ____ Revised Sheet No. D-1.00

D1. Power Supply Cost Recovery — **PSCRM**

1. PSCR FACTORS
All rates for metered electric Power Supply service shall include an amount up to the Power Supply Cost Recovery Factor (the PSCR Factor) for the specified billing period as set forth below. The PSCR Factor for the period covered shall consist of an increase or decrease of .010492 mills per kwh for each full .01 mill per kwh increase or decrease in power supply costs above or below a base cost of 38.79 mills per kwh rounded to the nearest .01 mills per kwh. The projected power supply and transmission service costs per kwh shall equal the total projected net power costs in that month divided by that month's net system kwh requirements.

An amount not exceeding the PSCR Factor for each month shall be placed into effect in the first billing cycle of that monthly billing period and shall continue in effect until the first billing cycle of a subsequent month for which a subsequent PSCR Factor becomes operative. This procedure shall apply to the following rate schedules:

Class of Service	Schedule No.
Residential	Rg-1M, Rg-2M, RG-OTOUM
Commercial & Industrial	Cg-1M, Cg-2M, Cg-3M, Cg-4M, Cg-OTOUM, Cp-1M, and Cp-ND
Other	Mp-1M

Power Supply Cost Recovery Factors

	Billing Months	Authorized 2013 Plan Year PSCR Factor $/kWh	Authorized PSCR Reconciliation Factor $/kWh	Maximum Authorized 2013 PSCR Factor $/kWh	Actual Factor Billed $/kWh
R	January 2013	$0.00394	$0.00000	$0.00394	
R	February 2013	$0.00394	$0.00000	$0.00394	
R	March 2013	$0.00394	$0.00000	$0.00394	
R	April 2013	$0.00394	$0.00000	$0.00394	
R	May 2013	$0.00394	$0.00000	$0.00394	
R	June 2013	$0.00394	$0.00000	$0.00394	
R	July 2013	$0.00394	$0.00000	$0.00394	
R	August 2013	$0.00394	$0.00000	$0.00394	
R	September 2013	$0.00394	$0.00000	$0.00394	
R	October 2013	$0.00394	$0.00000	$0.00394	
R	November 2013	$0.00394	$0.00000	$0.00394	
R	December 2013	$0.00394	$0.00000	$0.00394	

Continued to Sheet No. D-2.00

Issued:
By J F Schott
VP Regulatory Affairs
Green Bay, Wisconsin

Effective Jan - Dec
2013 Billing Months
Issued Under Auth. of
Mich Public Serv Comm
In Case No: U-17092