Public Service Commission of Wisconsin
Direct Testimony of Corey S.J. Singletary
Gas and Energy Division

Wisconsin Public Service Corporation
Docket 6690-UR-122

August 29, 2013

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

A. My name is Corey S.J. Singletary and my business address is the Public Service Commission of Wisconsin (Commission), 610 N. Whitney Way, P.O. Box 7854, Madison, Wisconsin 53707-7854. I am employed by the Commission as an Energy Policy Analyst in the Gas and Energy Division.

Q. Please state your educational background and experience.

A. I hold a Bachelor of Science degree in Biology and a Bachelor of Arts degree in International Studies from the University of Wisconsin–Milwaukee. I also hold a Master's Degree in International Public Affairs and a Graduate Certificate in Energy Analysis and Policy from the University of Wisconsin–Madison. I have worked with the Commission since May 2010. My work focusses on electric utility rate design and cost of service and a number of policy issues such as smart grid technology, smart grid enabled rates, rate-based energy efficiency and conservation incentives, distributed generation, wholesale energy market issues, and energy efficiency evaluation.

Q. Have you previously testified in proceedings before the Commission?

A. Yes, I have previously testified before this Commission in municipal and investor-owned electric utility proceedings on subjects such as electric cost-of-service and rate design, distributed generation, and conservation programs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the results of electric embedded cost-of-service studies (COSS) performed for Wisconsin Public Service Corporation (WPSC) 2014 test year. My testimony will also address the company's proposals to modify its distributed generation tariffs.

Q. Are you sponsoring any exhibits in conjunction with your direct testimony?

A. Yes. I am sponsoring exhibit Ex.-PSC-Singletary-1. This exhibit contains the following schedules:

1. Summary of Cost of Service Study Results
2. Summary of Differences in COSS Allocation Methods
3. Detailed WPSC Model COSS
4. WPSC Model Functionalized Cost by Rate Class
5. Detailed Capacity Model COSS
6. Interruptible Capacity Model Functionalized Cost by Rate Class
7. Detailed Time-of-Use Model COSS
8. Time-of-Use Model Functionalized Cost by Rate Class
9. Detailed Locational Model COSS
10. Locational Model Functionalized Cost by Rate Class
11. Allocation Factors
12. Development of Interruptible and DLC Credit
13. Analysis of "Production" allocator impact on Revenue Requirement
14. Equivalent Peaker Calculation
15. PG Distribution O&M Calculation

Q. Was this exhibit prepared by you or under your direction?

A. Yes.

Electric Cost of Service Studies

Q. Please describe what is shown in Schedule 1 of Ex.-PSC-Singletary-1.

A. Schedule 1 of this exhibit summarizes the results of the four cost-of-service studies performed for WPSC under Commission staff's audited revenue requirement. Commission staff witness Candice Spanjar discusses the development of staff's revenue requirement in her direct testimony. The four studies are:

- WPSC Model: Cost-of-service study performed using WPSC's COSS methodology. Adapted from WPSC response to PSCW data request 02-CSS-01 (PSC REF#: 188206).
- Capacity Model: The WPSC Model methodology modified so as to implement an interruptible credit for interruptible and direct load control capacity.
- Time-of-Use (TOU) Model: The Capacity Model methodology modified so as to allocate production plant costs on a demand and energy basis, with the demand/energy split based on an equivalent-peaker analysis.
- Locational Model: The TOU Model modified so as to allocate all primary and secondary system distribution costs associated with accounts 354-358 on a demand basis.

Schedule 2 of Ex.-PSC-Singletary-1 summarizes the differences in the allocation methods used in each model. Further detail can be found in the expanded model results shown in Schedules 3, 5, 7, and 9. In all four cases, the results are shown both with and without the inclusion of decoupling revenues (and associated tax expense) for rate design purposes.

General Approach

Q. Please briefly describe how the WPSC model was developed.

A. The WPSC model was developed using the spreadsheet model filed with WPSC response to PSCW data request 02-CSS-01. WPSC's COSS methodology is described in the direct testimony of WPSC witness Joylyn Hoffman Malueg.

Q. Were any modifications made to WPSC's COSS as filed?

A. A few small changes were made to the WPSC model. However, none of these changes significantly affect the results of WPSC COSS under staff's revenue requirement. First, I modified the WPSC model so as to allow for the presentation of COSS results with and without decoupling revenues. Second, I reincorporated an analysis of PG costs, which was not included in the filed data request response. This PG cost analysis differs somewhat from the approach used by Ms. Hoffman Malueg in preparing her exhibits and direct testimony and will be discussed below. Finally, I made a small formula change so as to calculate Return Income Deficiency consistently across all classes and the utility total. With the exception of the PG COSS class, the results I have presented for the WPSC model do not differ from the version filed by the company by more than 0.02 percent, and in most cases are within 0.01 percent of the results filed by WPSC in its data request response.

Q. Please describe how the Capacity model was developed.

A. The Capacity model considers an alternative approach to reflecting interruptible and direct load control (DLC) capacity in the COSS. Under WPSC's approach, the 12-month total of industrial variable-interruptible capacity (CP-I2) and direct load control capacity are subtracted out of the company's 12-month coincident peak demand (12-CP). This reduces the 12-CP demand allocation for classes with Interruptible and DLC capacity. This allocator is in turn used to allocate all production demand costs. Under the approach used in the Capacity model, production demand costs are allocated using gross 12-CP demand instead of net 12-CP demand. An interruptible credit is then applied to interruptible and DLC capacity in order to credit those customers and customer classes for the capacity resource that they provide to the utility. The allocation of other test-year costs in the Capacity model is consistent with the WPSC model method.

Q. Have you used this interruptible credit approach in any of the other studies you performed for WPSC?

A. Yes. The interruptible credit approach is used in all three studies I prepared as alternatives to the company's COSS.

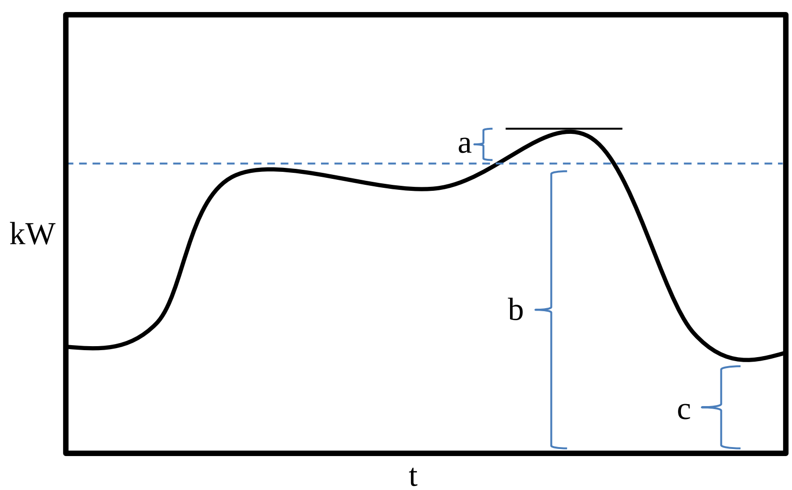
Q. Has Commission staff used an interruptible credit approach in preparing cost-of-service studies in past proceedings?

A. Yes. The general interruptible credit concept I have used in this case has been incorporated in the cost-of-service studies prepared by Commission staff for a number of years as an alternative to utility COSS methods, such as that used by WPSC, which net interruptible capacity out of their production demand allocation method.

Q. Are there issues with allocating production demand costs on a net-of-interruptible basis as WPSC has?

A. Yes. Using a net-of-interruptible demand allocator to assign responsibility for production demand costs overstates the value of interruptible capacity. This in turn results in an under-allocation of production demand costs to those interruptible customers.

While seemingly obvious, it bears emphasizing that the embedded cost-of-service study allocates forecasted costs of providing service to the utility's customers during the test year. That is, all 8,760 hours in the test year. To use a net-of-interruptible demand allocation method for production demand costs in a cost-of-service model is to assert that the following is true – that because WPSC's interruptible customers may be called upon to interrupt service for *at most* 600 hours, they should not be responsible for any demand-related costs involved with serving them the other 8,160 hours in the test year. For example, under this construct, interruptible customers would bear no responsibility for any demand costs associated with the company's baseload generating capacity. They would also bear no responsibility for demand costs associated with sub-peak load-following and system reliability. The figure below provides an illustration of this.



Interruptible customers provide the utility with a capacity resource that can be used to lower or avoid system peaks such as that labeled "a" in the simple load curve above. This provides a cost benefit to the utility and this value should be incorporated into the COSS in a manner reflecting the value of that capacity resource. However, removing interruptible, or *non-firm*, capacity from the demand allocation of all production costs creates a situation where interruptible customers do not bear any of the demand costs associated with meeting any *firm* demand interruptible customers may have during the times of system peak ("b"). Furthermore, even assuming a customer is 100 percent interruptible, the net-of-interruptible allocation method would cause an interruptible customer to bear no cost responsibility for costs associated with meeting non-peak, baseload or intermediate demand ("c").

I believe it is also important to consider that WPSC's use of a net-of-interruptible production demand allocation method is accompanied by a 100 percent demand allocation for all production plant. That is to say that all of WPSC's production plant, including the Columbia, Edgewater, Pulliam, and Weston coal-fired generating units. Because WPSC uses a 100 percent demand allocation for production plant, and because interruptible load is removed from WPSC's production demand allocator, interruptible load bears no cost responsibility for any of WPSC's production plant.

I believe it is also important to note that the net-of-interruptible "Production" allocator WPSC uses to assign production demand costs is also used to allocate a myriad of other test-year revenue requirement and rate base components, such as taxes. Schedule 13, of Ex.-PSC-Singletary-1 contains an analysis showing that, considering direct and indirect effects, nearly 30 percent of WPSC's test-year retail revenue requirement is allocated using the "Production" allocator.

Q. You indicated that using a net-of-interruptible demand allocation approach overstates the value of interruptible capacity. Can you please elaborate on that?

A. Yes. Let met start by considering the purpose of including interruptible capacity in a COSS.

In offering interruptible service, the utility is in effect purchasing a capacity resource from customers. Conceptually, these customers are then "paid" for providing this capacity resource via the COSS through a reduction in the class-level cost allocation. The benefit of this reduced class-level revenue requirement is then passed on to the individual customer(s) actually providing the interruptible capacity within that class through the application of a tariffed interruptible credit to the customer's bill.

This naturally raises the question of, if customers are "paid" through the COSS for their interruptible capacity, what is a reasonable price that the utility should pay for that capacity? This in turn raises the question of what, precisely is the resource that the company is buying? In the specific case of WPSC's CP-I2 interruptible customers, the utility is buying the option to call upon the customer's interruptible capacity for up to 600 hours per year, for 5 years. It would seem reasonable then to estimate the test-year value of CP-I2 interruptible capacity considering these "performance" characteristics.

Schedule 12 of Ex.-PSC-Singletary-1 shows the calculation of an avoided cost for interruptible capacity. I estimated an avoided cost of capacity based on the levelized $ per megawatt-hour cost of an advanced combustion turbine from the U.S. Energy Information Administration.[1] I also estimated avoided transmission costs based on Commission staff's audited test-year transmission expense and 12-CP transmission demand. Using the average annual hours of interruption since January 1, 2014, along with the average number of months with interruptions over the same period, I estimated a test-year avoided cost of $3.29 per kilowatt-month for interruptible capacity.[2]

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[1] 2018 Levelized Costs AEO 2013, U.S. Energy Information Administration - http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf (Accessed 8/20/13)

[2] Value of avoided transmission cost may be overstated as periods of peak transmission loads are not always coincident with peak WPSC system demands.

Q. In performing your avoided cost analysis for CP-I2 interruptible capacity, why didn't you use the 600 hour contract maximum allowed under the CP-I2 tariff?

A. First, over the last nearly ten years WPSC has never once called upon its interruptible capacity for the full 600 hours allowed under the CP-I2 tariff. In fact, over the last five years (2008-2012) the company has averaged only 40 hours of interruptions over five months per year, all of which were economic interruptions, rather than emergency interruptions for system reliability. WPSC has not called an emergency interruption since August 2006. Furthermore, the company has not called for a significant number of interruptions since 2006 and 2007. In those two years, the greatest number of hours any one interruptible customer was subject to, considering both economic and emergency interruptions, was 264.25 and 260.50 hours, respectively. A summary of historic interruptions is included in Schedule 12 of Ex.-PSC-Singletary-1.

Second, in developing a test-year avoided cost, I considered what a reasonable forecast for interruptions might be, not only for the test year, but for the next five years, a length of time consistent with the CP-I2 contract term. This was done in order to reflect a slightly longer-term system planning view. I believe that using the average over the last ten years allows for future uncertainty, while at the same time reflecting the amount of excess capacity in WPSC's portfolio.

Q. Are there any other issues with WPSC's use net-of-interruptible production demand allocation approach?

A. Yes. Ultimately, the issue with WPSC's use of a net-of-interruptible production demand allocation to reflect CP-I2 interruptible capacity is that excusing interruptible load from 100 percent of demand costs treats interruptible capacity as if it were 100 percent non-firm in every hour of the year. This would not be a problem if CP-I2 interruptible load truly were 100 percent non-firm, and if the customer had to pay marginal costs for all non-firm energy and demand. In fact, WPSC has just such a rate. The Real Time Market Pricing (RTMP) tariff authorized by the Commission in docket 6690-UR-120 charges the customer the hourly Midcontinent Independent System Operator, Inc. Locational Marginal Price (LMP) plus a transmission charge, applicable fees, taxes, and adders, for non-firm use. Like CP-I2, RTMP non-firm load is not included in the "Production" demand allocator and as such are not allocated any costs associated with their non-firm use. However in exchange, RTMP customers bear the risk associated with the price volatility and uncertainty of the wholesale energy market. CP-I2 customers, however, do not bear such price risk, and instead receive the benefit of embedded cost rates.

Q. Please describe how the TOU COSS model was developed.

A. The TOU model was developed by modifying the Capacity COSS so as to allocate production plant based on demand and energy. This is in contrast to the 100 percent demand allocation used by WPSC as noted above.

Q. What percent of production plant is allocated on demand, and what percent on energy, under the TOU model?

A. I used a 40/60 demand/energy split under the TOU COSS model. This is a conservative round estimate recognizing that it is not possible to precisely disentangle energy and demand costs. As shown below, my analysis of the costs of WPSC's actual generation portfolio could support a higher energy allocation than 60 percent.

Q. What was your demand/energy allocation for the TOU model based on?

A. The demand/energy allocation ratio was based on an equivalent-peaker study performed on WPSC's test-year generation capacity. One analysis performed in the study considers WPSC's test-year production plant cost and non-fuel O&M provided by the company. I also performed a similar analysis using Generation Plant costs produced by the EIA. The results of those analyses are shown in Schedule14 of Ex.-PSC-Singletary-1 and suggest that approximately 66 percent of WPSC's production plant cost is energy related.

Q. What is the purpose of an equivalent-peaker study?

A. The equivalent-peaker study recognizes different generation types play different roles in meeting the utility's electricity supply needs, and that the utility does not solely consider demand needs when building or purchasing generation plant. As described in the NARUC cost allocation manual:

"The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the cost of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand related in the cost of service study. The difference between the utility's total cost for production plant and cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy –related in the cost of service study."[3]

Put another way. If meeting demand were truly the only consideration in system planning, utilities would only build peaker units as these are the lowest cost on a $ per kilowatt (kW) basis. However, this is obviously not the case, otherwise the Commission would rule any investment in generation plant more expensive than a peaker

[3] Electric Utility Cost Allocation Manual. National Association of Regulatory Utility Commissioners, January 1992

on a $ per kW basis as imprudent. Utilities incur the higher cost (when considered on a $ per kW basis) associated with baseload and intermediate generating facilities because they are able to meet energy supply needs at a lower levelized $ per kWh cost. As such, one can consider that any costs incurred by the utility in excess of the cost of a peaker unit is done so to meet energy needs. The equivalent peaker study is a method for determining what percentage of the utility's production plant is demand-related and what percent is energy-related. The simplified example below illustrates this.

	Fixed Cost ($/kW)	Energy-Related "Excess" ($/kW)	% Demand-related	% Energy-Related
Peaker	100	-	0	100
Coal Plant	250	150	40	60

Q. What is the difference between the two equivalent peaker studies you performed?

A. The equivalent peaker study performed with test-year costs supplied by the utility considers the actual investment made by the utility in its production plant, and provides an analysis of the costs largely already authorized as prudent by the Commission. The analysis performed with EIA values asks the following hypothetical question: If the utility's generation portfolio were rebuilt today, considering the utility's need for different types of generation (coal, combined-cycle, peakers, renewables, etc.), what would the relative costs look like with today's plant costs? This attempts to consider, on more of a forward-looking basis, what the next best alternative option would cost. The equivalent peaker analyses I performed are based on the methods outlined in the National Association of Regulatory Utility Commissioners cost allocation manual.

Q. Please describe how the Locational COSS model was prepared.

A. The Locational COSS was prepared by modifying the TOU study so as to allocate all Distribution account 354-358 costs (plant and O&M) that are allocated on a customer basis under WPSC's COSS approach, instead on a non-coincident peak demand basis.

Q. Why was the Location distribution COSS approach used?

A. WPSC's distribution cost allocation method uses the minimum system approach. Under that method, the smallest installed unit of the distribution system (shortest pole, smallest conductor, etc.) is used as the basis for estimating customer-related costs. Costs in excess of this minimum size are considered demand-related costs. Conceptually, this is not entirely-dissimilar to the equivalent peaker method for allocating production plant. However, some analysts believe that the minimum system method, such as employed by WPSC, overstates the allocation of customer-related costs. This is due to the fact that, even the minimum size distribution system components, such as the smallest overhead or underground conductor, have a load-carrying capacity and as such, part of what is allocated as customer-related under the minimum system method would more accurately be functionalized as demand-related. As a result it is believed that the minimum system method does not adequately reflect customer density and location, such as in urban environments, or dense residential areas. Conversely, the minimum system potentially understates customer-related costs by eliminating all customer costs except for meters and services. The Location study can thus be considered as a counterpoint alternative to the TOU study with respect to distribution cost allocation.

In fact, the appropriate treatment of distribution system costs is a long-standing issue, with some believing that such costs are neither appropriately classified as customer costs nor as demand costs, but are instead a "strictly unallocable portion of total costs,"[4] and it is merely due to the desire to achieve perceived "precision" in cost allocation that analysts inappropriately "fudge"[5] the allocation of such costs.

Unquestionably, if one were seeking a definitive sense of one "correct" cost allocation approach, the notion of "unallocable" costs is not particularly helpful and in fact may create more questions than it answers. However, the conclusion that there is no *one* "right" answer does suggest that the "truth" may lie somewhere in between two imperfect answers.

Q. Is there one "correct" cost of service approach?

A. No. COSS models represent different views of how the utility's system functions and how costs are incurred. There is no uniform consensus regarding cost-of-service methodologies as different parties can hold different beliefs in the relative theoretical strengths and weaknesses of different COSS approaches. Additionally, parties may also develop a preference over time for certain COSS methods simply because they produce results more favorable for their interests, irrespective of the theoretical merits or weaknesses of any such preferred approach. Indeed, if such a consensus existed in the realm of cost allocation, utility rate cases would likely be far less contentious. Recognizing this reality, this Commission has long used the practice of considering more than one COSS in informing final revenue allocation.

That being said, I do not believe it to be unreasonable to consider the reasonableness of any one particular COSS approach (and correspondingly how much weight said COSS results should be given) as a function of how well that approach

[4] Bonbright, James C., *Principles of Public Utility Rates*, New York and London: Columbia University Press, 1961., p. 348.
[5] Id., p. 349.

mirrors the actual function of the system being modeled. When considered on that basis, I believe that Commission staff's TOU and Location COSSs provide the most reasonable allocation of WPSC costs, for the following reasons:

1. As noted above, the net-of-interruptible production demand allocation used in the WPSC COSS does not accurately reflect the costs incurred by the utility to meet customer electricity needs during the test year. The interruptible credit approach used on Commission staff's COSS models more accurately reflects the nature of the CP interruptible service and a reasonable estimate of utility avoided costs in the test year.
2. The 100 percent demand allocation of production plant used in the WPSC and Capacity COSS does not accurately reflect what we know to be true about the utility's generation portfolio. To accept the 100 percent demand allocation method as reasonable is to accept the premise that generation plant costs are incurred solely to meet peak demand needs. As noted above, this would require the utility to build only peaking units as any other generation plant type would be imprudent when considered on a relative $ per kW cost basis. We know this to be untrue as WPSC owns significant baseload coal generating capacity and was recently granted authorization to purchase approximately 500 megawatts of high capacity factor combined cycle generation. A demand/energy split as used in Commission staff's

TOU and Location Study more accurately reflects WPSC's actual generation portfolio.

3. As noted above, the allocation of distribution system costs is likely not accurately represented by any one discreet COSS method due to the unallocable nature of certain distribution system costs. If one accepts that the minimum system method used in the TOU model likely overstates customer-related distribution costs, and that the Location model likely understates these costs, a reasonable conclusion would be that the "truth" lies somewhere in between these two.

Distributed Generation Tariffs

Q. Did you review WPSC's proposal to modify its distributed generation tariffs?

A. Yes. The changes WPSC is proposing for its distributed generation tariffs are addressed in the direct testimony of WPSC witnesses Durga P. Kar and Russell T. Laursen. I will address the following proposed changes in my direct testimony.

1. WPSC's proposal to increase the customer charge for Pg-2 customers. (Kar)
2. WPSC's proposal to implement a capacity credit for Pg-2A and Pg-2B customers. (Kar).
3. WPSC's proposal to reduce the availability of its Pg-4 Net Energy Billing tariff from 100 kW to 20 kW. (Laursen)
4. WPSC's proposal to address the current Pg-4 grandfathering clause. (Laursen)

5. WPSC's proposal to disallow Response Rewards customers from enrolling under Pg-4. (Laursen)

Q. What change to the Pg-2 customer charge has WPSC proposed?

A. As described in Mr. Kar's direct testimony, the company is proposing to increase the Pg-2 customer charge from $10 per month to $20 per month. This customer charge is assessed to Pg-2A and Pg-2B customers. Pg-2C customers sell power to WPSC under negotiated rates and so are not subject to the same customer charge.

Q. Do you agree with WPSC's proposed change to the Pg-2 customer charge?

A. No. I do not. The increase in the customer charge is based on the company's COSS, which suggests that the cost of service for Pg-2 customers is $68.46 per month. However, I believe that the company's COSS dramatically overstates the cost to serve Pg-2 customers.

Q. Please explain.

A. The cost assigned to the "Pg" class under the utility's COSS is based primarily upon distribution O&M costs which are directly assigned to the class. This direct allocation is based on the following assumptions:

1. The PG class is made up of all Pg-2, and Pg-Solar customers. (Presumably it would also include any Pg-Biogas customers if there were any.)
2. The distribution O&M for Pg-2 customers is equal to the per-customer O&M expense of the average Cg-20 customer.
3. The distribution O&M for Pg-Solar customers is equal to the per-customer O&M expense of the average Rg-1 residential customer.

4. The total distribution O&M for the Pg class is equal to the estimated cost per customer times the total number of Pg customers.

While this may seem intuitive and reasonable, the end result is that Pg customers are in effect double charged for distribution costs. This is due to the fact that WPSC's COSS ignores the fact that nearly all (if not all) Pg customers also take service under a standard retail consumption tariff. These O&M costs are recovered through the retail rates charged under the customer's consumption tariff, and do not need to be recovered through Pg customer charges. WSPC's COSS methodology implies that either Pg customers cause the utility to incur twice the distribution O&M expense of a similar customer without generation, or that there is no other source of revenue collected from Pg customers for service at any given premises. This is problematic as the utility has not submitted any evidence to support the former, and the latter is refuted by data supplied by the company. Specifically, data provided in WPSC's Response to PSCW Staff Data Request 02-CSS-02 (PSC REF#: 188615) shows that *at most*, 4 of the 25 customers currently taking service under a Pg-2 tariff do not have a retail consumption tariff associated with their Pg-2 account. However, it should be noted that, as indicated by the company, it is at the customer's discretion to have different accounts for different services. As a result it is entirely possible that those four customers pay for electricity service at the location where their generator is located but under a separate account.

It would seem reasonable then that if one were performing a COSS in order to determine the appropriate allocation and rates for the Pg class, that only the costs associated with customers who do not pay for service at the same location under a retail tariff should be considered. This is the approach used in all of the COSS I have prepared.

All costs are allocated to the PG class based solely on the 4 customers whose generation meters' accounts are not associated with a consumption tariff. In performing the functionalized cost analysis, the revenue requirement is then divided by the total Pg customers (Pg-2 and Pg-Solar) in order to arrive at an average cost per customer for all Pg customers. I have also performed a separate simplified Pg cost analysis that considers the Pg-2 and Pg-Solar customers separately and what the approximate cost to serve is under the WPSC and Locational COSS. The results of this analysis are shown in Schedule 15 of Ex.-PSC-Singletary-1, and suggest that the cost to serve Pg-2 customers is *at most* somewhere between $14 and $25. If in fact, all Pg-2 customers take service under a retail tariff at the same location as their generation, this cost would go down, potentially to zero.

Based on this analysis, I believe it would be difficult to support an increase in the customer charge at this time. If there is significant concern regarding cost recovery from Pg customers, the Commission may wish to direct the utility to perform a more detailed cost analysis of Pg service, and submit the results of such a study in WPSC's next full rate case.

Q. Do you have any other comments regarding Pg customer charges?

A. Yes, as shown in Schedule 15 of Ex.-PSC-Singletary-1, the potentially "unrecovered" O&M costs associated with Pg-2 service is extremely low - estimated at between $4,200 and $7,500 for the entire test year. This is an immaterial value compared to the utility's total revenue requirement. However, doubling the Pg-2 customer charge as the company suggests has the potential to dramatically affect Pg-2 customers, particularly those with smaller generation units. When considered in tandem with the company's request to restrict the availability of the Pg-4 net energy billing tariff, and in light of the tenuous cost basis for the increase, the potential impact to customers with small distributed generation may vastly outweigh any cost recovery benefits.

Finally, I would also stress that these analyses consider only the possible (but not definitive) costs of distributed generation and do not include an accounting of any possible benefits or avoided costs that may be produced by customer owned distributed generation.

Q. Do you have any comments regarding WPSC's proposed implementation of a capacity credit for Pg-2A customers?

A. Yes. The proposed on-peak capacity credit Mr. Kar has proposed appears to be consistent with the intent of the Commission's final decision in Docket 6690-UR-120. However, given that this is relatively new approach, and considering the fact that other utilities will soon be filing modifications to their Pg tariffs in compliance with similar capacity credit language in their respective tariffs, the Commission may wish to direct that a review of these market-based buyback rates be conducted in a future rate case.

Q. Do you have any comments regarding WPSC's proposal to reduce the availability of its Pg-4 Net Energy Billing tariff from 100 kW to 20 kW?

A. Yes. While Mr. Laursen does indicate that WPSC is concerned about possible fixed cost recovery issues associated with Pg-4 service, I would note that neither he nor any other WPSC witness has introduced any quantitative evidence into the record that would support restricting service for Pg-4 customers.

Q. Have you performed an analysis of the fixed cost recovery impact of Pg-4?

A. Yes. Using information provided by the company about its current population of Pg-4 customers I have estimated possible "losses" between approximately $93,000 and $117,000 per year in fixed cost recovery across 299 Pg-4 customers, when compared against class averages. The results of this analysis are shown in Schedule 15 of Ex.-PSC-Singletary-1. This represents, at most, little more than one one-hundredth of one percent of WPSC's total retail revenue requirement. Additionally, it must be noted that this is merely a rough estimate, only considering costs, and does not include any analysis of any possible system benefits or avoided costs that may be produced by customer owned distributed generation under Pg-4. As it would seem reasonable to consider both costs and benefits when evaluating cost responsibility, the Commission may wish to direct that a more in depth analysis be performed, with the results of such an analysis submitted in a future base rate case. Alternatively, the Minnesota Public Utilities Commission has recently opened a proceeding that will examine the benefits associated with solar photovoltaic distributed generation, the results of which could be used to estimate benefits for Wisconsin utilities. As the data provided by either or both of these options may prove informative to Commission on this and other distributed generation issues, the Commission may wish to wait until it is able to consider more evidence before deciding on any restrictions in Pg-4 service.

Q. Do you have any other comments regarding WSPC's Pg-4 service?

A. Yes.

First, it should be noted that since WPSC has the most restrictive net metering service of any Wisconsin utility (monthly netting with LMP based avoided cost paid for net surplus generation), any "lost" energy sales under Pg-4 net metering are basically indistinguishable from reductions in sales through energy efficiency or conservation.

Finally, it is worth noting that the Pg-4 tariff provides a means by which small to medium sized customers, both residential and commercial, can control their energy costs. This is consistent with the Commission's recent decision in the Wisconsin Power and Light 2013 test-year fuel case,[6] with respect to above-market-cost distributed generation buyback rates. In that proceeding the Commission recognized the cost-control value that distributed generation confers to customers in supporting its decisions, particularly with respect to businesses in a still-sluggish economy.[7] This is noteworthy as nearly one-third of Pg-4 customers are small to medium commercial & industrial class customers, and all of the customers who have enrolled under Pg-4 since 2011 with generation between 20 and 100 kW are commercial customers.

Q. What is WPSC's proposal to address the current Pg-4 grandfathering clause?

A. As indicated in Mr. Laursen's direct testimony, WPSC is proposing to modify the Pg-4 tariff so as to indicate that the grandfathering treatment currently authorized for customers that took service under the Pg-4 tariff prior to March 31, 2011, be extended until December 31, 2021. All told, this would give those customers 10 years under the previous retail rate credit treatment, at which point those customers would presumably be transitioned to the prevailing tariff available at the time. I believe this 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.

[6] Final Decision, Docket 6680-FR-105, Issued December 7, 2012 (PSC REF#: 177617)
[7] Id., Concurring Opinion Of Chairperson Phil Montgomery

Q. Do you have any comments regarding WPSC's proposal to limit the availability of the Pg-4 net energy billing tariff to customers taking service under energy-only rate schedules and to customers that are not participating in a Response Rewards tariffs?

A. Yes. First, with respect to the proposal to limit Pg-4 to energy-only rate schedules, the utility's proposed restriction would appear unnecessary given that Pg-4 provides an energy benefit only. Demand cannot be "rolled back" as energy can over the course of the netting period. Since demand-energy rate schedules typically have lower energy charges than energy-only schedules, this would provide a limited incentive to oversize generation with respect to load. Additionally, since demand-energy customers such as Cg-20 and Cp-1 are assessed energy, monthly demand, distribution demand, and customer charges, the unrecovered fixed cost issue identified earlier by Mr. Laursen is less of an issue as demand billing units are not affected by the net metering treatment. With respect to demand charges, fixed cost recovery for demand metered customers under Pg-4 would be no different than if that customer were under one of the company's Pg-2A or Pg-2B tariff. As the Pg-2 tariffs are not restricted to energy-only customers, it seems unreasonable to impose such a restriction on Pg-4.

Second, regarding Mr. Laursen's proposal that response rewards customers be denied eligibility for Pg-4. Based on the cost information provided by WPSC in response to PSCW Staff Data Request 01-CSS-03 (PSC REF#: 186894), the magnitude of the "administrative burden" cited by the company appears to be small, approximately $40 per bill, per customer. Given that there is currently only one response rewards customer taking service under Pg-4, this would seem to be an unnecessary restriction, if cost is the primary driver. Moreover, the administrative burden associated with billing response rewards customers under Pg-4 appears as though it will be a short-lived issue. WPSC is currently in the process of a billing system migration project. According to the company, the billing system functionality necessary to eliminate the manual nature of the current process would be eliminated upon completion of the migration project. It is my understanding that the billing system migration will be completed sometime over the next twelve months. In all, the short term administrative burden associated with manually billing a small number of response rewards until such time as WPSC's new billing system is active would appear to fall into the category of "the cost of doing business," and as such I do not believe that the company has provided sufficient justification for the proposed restriction.

Q. Does this conclude your direct testimony?

A. Yes.

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