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

Madison Gas and Electric Company
Docket 3270-UR-120

September 18, 2014

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 focuses on electric utility rate design, cost of service, and a number of policy issues such as smart grid technology, smart grid-enabled rates, rate-based energy efficiency, conservation incentives, and distributed generation.

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) and a proposed rate design for the Madison Gas and Electric Company (MGE) 2015 test year.

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

A. Yes. I am sponsoring exhibit Ex.-PSC-Singletary-1 and Ex.-PSC-Singletary-2.

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

A. Yes.

Electric Cost of Service Studies

Q. Please briefly describe the approach you in preparing your COSS.

A. As detailed in her direct and second supplemental direct testimony, MGE witness Son Trinh prepared the following three studies in this proceeding:

- MGE's "Standard" COSS
- 1CP COSS
- Time-of-Use (TOU) COSS

These three studies were adjusted for Commission staff's audited revenue requirement. Commission staff witness Jodee Bartels discusses the development of the test-year revenue requirement in her direct testimony.

In addition to these three studies, a Location or Locational COSS was prepared. In past cases, MGE has provided the results of a Locational COSS. However, in this proceeding the utility opted not to include the results of a Locational COSS, indicating that "MGE believes the standard and time-of-use cost of service studies provide an adequate range of results from which the Commission can review the Company's revenue allocation." The Locational study has historically been the preferred COSS of intervening parties representing residential and small commercial customers, such as

Citizens Utility Board (CUB). While MGE did not include a Locational COSS in this case, in response to a request made by a customer, the company did add the aforementioned 1CP COSS to the range of studies presented.

Q. Did you prepare any other COSS?

A. Yes. The four studies mentioned above all incorporate MGE's preferred treatment of Cp-1 interruptible capacity in the allocation of production costs. For reasons I will discuss below, Commission staff has historically not been comfortable with this production cost allocation approach. Accordingly, I also prepared "Capacity" variants of the "Standard," 1CP, TOU, and Locational studies. The class retail revenue increases suggested by my studies are summarized below. Additional detail can be found in pages 1 through 11 of Ex.-PSC-Singletary-1, Schedule 1.

		GENERAL SERVICES			BUSINESS SERVICES				
	Total Utility	Residential	Small C/I	Light/Misc Services	Cg-4	Cg-2, Cg-6	Cp-1	Sp-3	Sp-4
MGE Production Cost Allocation									
1CP	4.13%	7.69%	-13.74%	-10.22%	3.47%	6.04%	-1.28%	4.81%	0.75%
"Standard"	4.13%	2.21%	-11.11%	7.17%	5.22%	8.71%	5.65%	6.85%	7.62%
TOU	4.13%	1.70%	-11.30%	7.45%	4.73%	8.66%	23.98%	7.41%	8.14%
Locational	4.13%	-0.43%	-11.98%	0.47%	6.14%	10.17%	23.98%	8.38%	8.98%
Staff "Capacity" Production Cost Allocation									
1CP	4.13%	7.74%	-13.70%	-10.21%	3.50%	5.18%	3.63%	4.87%	0.81%
"Standard"	4.13%	2.15%	-11.17%	7.12%	5.10%	7.68%	33.02%	6.76%	7.53%
TOU	4.13%	1.40%	-11.24%	8.12%	4.48%	8.06%	38.76%	8.47%	9.14%
Locational	4.13%	-0.72%	-11.92%	1.15%	5.89%	9.57%	38.76%	9.44%	9.99%

Q. Can you please describe how the "Standard," 1CP, TOU, and Locational studies were prepared?

A. The "Standard," 1CP, and TOU studies were prepared using the company's COSS models, adjusted for Commission staff's revenue requirement. Additional detail regarding the preparation of these studies can be found in Ms. Trinh's direct and second supplemental direct testimony. The Locational study was prepared by modifying the TOU study so as to allocate distribution plant accounts 364-Poles, Towers & Fixtures; 365-Overhead Conductors & Devices; and 368-Line Transformers on a 100 percent demand basis. Distribution operation and maintenance expenses associated with these facilities are similarly allocated on a 100 percent demand basis.

Q. Why was the Locational model prepared?

A. MGE'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 and classifying customer-related costs. Costs in excess of this minimum size are classified as 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 MGE, overstates the allocation of customer-related costs. This is due to the fact that, even the minimum size distribution system components (*e.g.* the smallest overhead or underground conductors) have a load-carrying capacity. As a result it is argued that part of what is allocated as customer-related under the minimum system method would more accurately be classified as demand-related. Because of this, 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 Locational study potentially understates customer-related costs by eliminating all customer classified costs except for meters and services. The Locational study can thus be considered as a counterpoint to the TOU study with respect to distribution cost allocation.

Q. Do you believe that one of these distribution cost allocation approaches is more reasonable than the other?

A. I would tend to agree with the sentiment that both the minimum system method and the Locational method both have their shortcomings. I would also agree that the minimum system method likely overstates proportion of distribution costs that are customer related, especially in a predominantly urban and dense suburban service territory, such as MGE's. Similarly, there is likely some portion of distribution costs, even if it might be very small, that is customer related, and as such should be allocated on a customer basis.

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,"[1] and it is merely due to the desire to achieve perceived precision in cost allocation that analysts inappropriately "fudge"[2] 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 our two imperfect

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

answers—between the results suggested by the minimum system and Locational approaches.

Q. Please briefly discuss the TOU COSS model.

A. Under the TOU COSS production plant costs are split, with 60 percent allocated on demand and 40 percent allocated on energy. This is in contrast to the 100 percent demand allocation used in MGE's "Standard" and 1CP COSS.

As noted by Ms. Trinh, the theory behind the TOU COSS this is that base load plants have a dual role of meeting peak demands and providing energy at the lowest possible cost. If demand were the only consideration, then peaking plants, which have a lower installed cost per kilowatt (kW), could be built in place of large base load units. However, the cost of energy is also a factor in determining what type of unit is installed. For example, base load plants are built because they have lower energy costs than peaking units. Using a combined energy/demand allocator reflects the trade-off between operating expense and initial plant cost made by MGE when it decided what plants should be built.

Q. MGE used a 60/40 demand/energy split for the TOU COSS. Did you examine what demand/energy split is appropriate for MGE?

A. Yes. I performed a simplified equivalent peaker study using test-year production plant data supplied by the utility. Based on this analysis I determined that a demand energy ratio of 40/60 could be supported. While using the 40/60 ratio instead of the utility's 60/40 ratio would produce slightly different results for both the TOU and Locational studies, I used a 40/60 demand/energy split in preparing COSS for this case. I did this for a couple reasons. First, I used the same value as Ms. Trinh so as to simplify comparisons between the studies she prepared and those that I prepared. Second, shifting to a 40/60 ratio would move the final class COSS allocations farther away from the utility average. classes with a below average increase would now be allocated an even smaller increase and those with an above average increase would get an even larger increase. While this is not an inappropriate result, it is not terribly helpful from a revenue allocation perspective. In assigning final revenue allocation, high and low revenue adjustments are typically brought closer to the average in the interest of equity. The 40/60 COSS results would simply amplify the highs and lows farther away from the range one would typically contemplate for final revenue allocation.

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 National Association of Regulatory Utility Commissioners 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 dollar per kW basis. However, this is obviously not the case; otherwise the Commission would

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

rule any investment in generation plant more expensive than a peaker on a dollar per kW basis as imprudent. Utilities incur the higher cost (when considered on a dollar per kW basis) associated with baseload and intermediate generating facilities because they are able to meet energy supply needs at a lower levelized dollar per kilowatt-hour (kWh) cost. As such, one can consider that the costs incurred by the utility in excess of the cost of a peaker unit is incurred in order 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.

Q. Can you please discuss Commission staff's "Capacity" production cost allocation method?

A. Yes. The "Capacity" production cost allocation method considers an alternative approach to reflecting interruptible capacity in the COSS. Under MGE's production cost allocation approach, Cp-1 coincident peak (CP) demand is subtracted out of the company's coincident peak demand, whether that be 12-month (12CP) or 1-month (1CP) coincident demand. This reduces the coincident peak demand allocation for the Cp-1 class. More specifically, since the one customer taking service under Cp-1 is 100 percent non-firm, the CP demand for the Cp-1 class is zero. This net CP allocator is used to allocate all production demand costs. Under the approach used in the "Capacity" models, production demand costs are allocated using gross CP demand instead of net CP demand. An interruptible credit is then applied to interruptible capacity in order to credit those customers and customer classes for the capacity resource that they provide to the utility. Under Commission staff's "Capacity" method, all interruptible capacity is recognized in the COSS, not just Cp-1. The allocation of other test-year costs under the "Capacity" COSS variants is consistent with MGE's allocation methods.

Q. Do any Wisconsin utilities use a production plant allocation method similar to Commission staff's interruptible credit approach?

A. Yes. Wisconsin Electric Power Corporation (WEPCO) uses a method that is conceptually identical to Commission staff's interruptible credit approach. WEPCO allocates production plant costs based on average CP demand, then applies a production plant cost credit to classes with non-firm loads. While there are some differences between the way in which WEPCO calculates its non-firm production cost credit and the derivation of staff's interruptible credit, the approaches are generally the same.

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

This is particularly important considering that, under MGE's "Standard" COSS, the use of a net-of-interruptible production demand allocation method is accompanied by a 100 percent demand allocation for all production plant, and approximately one-third of production expense, including some fuel and purchased power expense. When considered together, MGE's use of a 100 percent demand allocation for production plant, together with a net-of interruptible production demand allocator, produces COSS results wherein the Cp-1 class bears no cost responsibility for any of MGE's production plant including the Columbia, Elm Road coal-fired generating units, and the West Campus gas-fired combined-cycle generating facility. This is particularly problematic when one considers that the Cp-1 class is, by design, a high load factor customer class.

It bears emphasizing that the embedded COSS 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 Cp-1 may be called upon to curtail load for a few hundred hours a year, that customer should not be responsible for any demand-related costs involved with serving that same load during the other hours in the test year.

Q. Are there any other issues with the utility's net-of-interruptible production demand allocation method?

A. Yes. A number of other test-year revenue requirement and rate base components are also affected by the use of the net-of-interruptible CP allocator. For example, as is the case with many utilities, MGE's COSS allocates income tax expenses on net investment rate base. Rate base is, in turn, obviously affected by the allocation of production plant. There is nothing necessarily wrong with this tax allocation method, provided that the underlying allocation of rate base is reasonable. However, MGE's net-of-interruptible production demand allocation method allocates only 0.06 percent of the utility's total income tax expense to the Cp-1 class, despite the class making up about 1.26 percent of the utility's total retail revenue. This produces a situation where Cp-1 contributes 0.09¢ in income taxes for every $1.00 in revenue as compare to 1.43-2.43¢ per $1.00 for all other classes. Considering in reality the utility incurs income tax expenses at the company level, not at the class level, I do not believe it makes sense for the Cp-1 to contribute a disproportionately smaller sum towards the utility's tax expense.

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 me start by considering the purpose of reflecting 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. In the case of Cp-1, since all class load is interruptible, this rate level credit manifests in the form of a lower monthly billed demand charge than for firm service rates.

This raises the question: 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 MGE's interruptible customers, the utility is buying the option to call upon the customer's interruptible capacity for up to 300 hours a year for five years. It would seem reasonable then to estimate the test-year value of CP-I2 interruptible capacity considering these performance characteristics.

Pages 7 and 9 of Ex.-PSC-Singletary-1, Schedule 1, shows the calculation of estimated avoided costs for interruptible capacity, based on various hours of interruptions and numbers of months with interruptions. I used an avoided cost of capacity based on the levelized dollar per megawatt-hour cost of an advanced combustion turbine from the U.S. Energy Information Administration. This source data is provided in Schedule 1 of Ex.-PSC-Singletary-2. I also estimated avoided transmission costs based on Commission staff's audited test-year transmission expense and 12CP demand.

Q. What values did you use for the interruptible credit under the "Capacity" COSS variants?

A. In MGE's last full rate case, docket 3270-UR-118, I used the tariffed interruptible credit rates authorized by the Commission as the basis for the COSS interruptible credit. In light of my analysis of the value of various levels of interruptions, I opted to again use the currently authorized tariffed interruptible credit rates of $3.75 per kW for Is-3 and $4.00 per kW for Is-4 in preparing the four "Capacity" COSS variants. For Cp-1 I used a higher value of $6.00 in order to reflect the fact that Cp-1 carries with it a longer 15-year contract commitment, and no specified maximum hours of interruptions per year. The $6.00 value is based on 300 hours of interruptions and interruptions occurring in six months out of the year. This likely overstates the avoided cost value of Cp-1 interruptible capacity. However, recognizing the fact that staff's "Capacity" COSS approach has historically been poorly received by MGE's Cp-1 customer, the $6.00 value was chosen as a compromise value of sorts, assigning a value to Cp-1 capacity on the "optimistic" end of the range.

Q. Could you please comment on the 4-CP COSS prepared by MGE?

A. As noted previously, it is my understanding that MGE has prepared the 1CP study in response to a request from a customer. It does not appear that MGE is itself supporting this allocation method, but instead has provided this information so as to better supplement the record. On this last point I would like to commend the utility for providing the results of alternative COSS methods as this allows for an apples-to-apples comparison, and undoubtedly assists the Commission in determining revenue allocation.

I believe that it is reasonable to evaluate the various cost allocation model approaches based on how well those methods mirror what we know to be true about the system being modeled. When considered on that basis, I believe that the 1CP is not an appropriate production demand allocation method and, to the extent that one is using a monthly coincident peak allocation method, that a 12CP allocation method is the most appropriate.

Fundamentally, the issue with the 1CP method is that it requires that one accept the premise that MGE's production capacity costs are incurred only to serve peak loads during the highest month of the year, and that capacity needs and reliability in all other months are irrelevant. MGE has built generation and purchased capacity in order to meet reliability standards. Similarly, MGE schedules and operates its production resources in order to meet reliability standards. While these reliability standards are based on analyses that show that the greatest reliability risk exists during peak summer months, it is important to recognize that the utility's production plant, including peaking resources, provides reliability in every month of the year. If this were not true, Midcontinent Independent System Operator, Inc. (MISO) would allow MGE and other generation owners to schedule maintenance projects on their generating facilities during non-peak months without restrictions. In fact, there are strict rules that require utilities to ensure that these plants are available to operate during the entire year, with maintenance scheduling also subject to strict rules. Therefore, we must assume that all of MGE's generating plants provide reliability during the entire year, not just during a single summer peak month.

In addition to reliability, utilities ensure that their power plants are available during the non-summer months because they provide the utility and its customers with a hedge against the risk of purchasing energy at a high cost. The 1CP study assumes that this cost-hedge has no value during the non-summer months.

A simple example that highlights the need to consider capacity in all months of the year can be found by looking back at 2013-2014 North American cold wave, or "Polar Vortex," as it is colloquially called. The extreme cold weather events experienced in January and February 2014 set a new winter peak and, coupled with a large amount of forced outages, caused the MISO region to experience tight operating conditions, which in turn produced significantly elevated MISO Locational Marginal Prices. January and February are not typically peak demand months for MGE. However, this recent experience highlights how generation capacity availability and reliability are just as important during non-peak months and should be considered when considering utility production cost of service.

Q. Is there one correct cost of service approach?

A. No. COSS models represent different views of how a 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 positions regarding 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 believe it is appropriate to consider the reasonableness of any one particular COSS approach (and correspondingly how much weight said COSS results should be given) according to how well that approach mirrors the actual function of the system being modeled, and how well the costs of system components are assigned to those who benefit from them. When considered on that basis, I believe that Commission staff's "Capacity" TOU and "Capacity" Locational COSSs provide the most reasonable basis for the allocation of MGE's costs, for the following reasons:

1. As noted above, MGE's net-of-interruptible production demand allocation does not accurately reflect the costs incurred by the utility to meet customer electricity needs during the test year. The interruptible credit approach used in Commission staff's "Capacity" COSS models more accurately reflects the nature of interruptible service and a more reasonable estimate of utility avoided costs in the test year.
2. The 100 percent demand allocation of production plant used in "Standard" and 1CP studies (both MGE's version and the "Capacity" variant) 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 dollar per kW cost basis. We know, however, that MGE owns and leases significant baseload coal generating capacity. A demand/energy split as used in the TOU and Locational Studies more accurately reflects MGE'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 Locational model likely understates these costs, a reasonable conclusion would be that the most reasonable estimate of class cost of service lies somewhere in between these two.

Electric Rate Design

Q. Could you please describe the class revenue allocation reflected in the proposed rate design?

A. Page 1 of Ex.-PSC-Singletary-1, Schedule 2, summarizes the class revenue allocation. The overall electric revenue increase of staff's audited revenue requirement is 4.13 percent. The class rate increases or decreases are based mostly on the "Capacity" TOU COSS. In designing rates, I also sought to limit the increase to any cost of service rate group to no more than 5.5 percent, so as to moderate the impact on customers within any specific rate class. As a result, the residential and small commercial classes have rate increases higher than what is suggested by the COSS.

Q. Please describe the approach you took in developing your proposed rate design.

A. I developed my proposed rated design based on the rate design presented by MGE witness Steven James in his second supplemental direct testimony. The following highlights the major adjustments I made to Mr. James' rate design.

- Increase in overall revenue to achieve staff audited revenue increase of 4.13 percent.
- Limited total increase in fixed charges to 20 percent over present rates for Residential, small commercial (Cg-5, Cg-3), and Cg-4 customer classes.

- Set a grid connection charge of $2.09 per month for residential and small commercial customers (Cg-5, Cg-3).
- Removed MGE proposed Rg-7, Cg-7, and Cg-8 distributed generation rate classes.
- Removed MGE proposed Rg-6 low income rate class.

My proposed rate design can be found starting on page 2 of Ex.-PSC-Singletary-1, Schedule 2.

Q. Did you prepare a class cost analysis that would suggest what an appropriate fixed charge level would be for residential and small commercial customer classes?

A. Yes, using MGE's "Standard" COSS model, I considered what class-level functionalized costs would be appropriate to include in customer fixed charges. Historically, Commission staff has approached such an analysis by considering what bare bones basket of costs that would vary by customer. This typically included meter costs, service drops, and some administrative and general costs.

Sympathetic to some of the utility's concerns regarding cost recovery, I performed a functionalized cost analysis that considered more customer related costs than just this limited set. In order to arrive at a fixed-cost analysis more inclusive than a bare-bones approach, I performed a functionalized cost analysis that excluded customer related primary-voltage distribution. I believe that this is a reasonable method for determining a fixed-cost contribution level as it includes all of the distribution costs most proximal to the end use customer—costs one would reasonably expect to vary by customer. This includes distribution costs extending from the meter, up through the service drop back up through the secondary distribution system, including any line transformers. In addition to distribution costs this method also includes all other customer classified costs included in the utility's functionalized analysis, including administrative and general costs. As this cost analysis is meant to inform rate design, I do not believe it is appropriate to include primary-voltage distribution-system costs as it is hard to contemplate a scenario where primary system costs would be significantly affected by the addition or subtraction of residential or small commercial customers on MGE's system.

Q. What fixed cost levels are suggested by this analysis?

A. The adjusted functionalized cost analysis I performed suggests the following fixed cost levels per customer. As these values are intended to represent customer classified costs that reasonably vary by customer, I believe it is appropriate to consider these values as an upper bound when setting customer fixed charges.

Residential	Sm. Commercial
$17.43	$18.97

Q. Why have you presented this cost analysis?

A. I believe that if the Commission wishes to consider increasing fixed charges in order to address fixed-cost recovery issues, it is important to focus on more than just the dollar rate level, but also the underlying cost basis for the rate and what costs the Commission believe are reasonable to include in a fixed charge. If the Commission does not wish to consider what costs are reasonable to recover through a fixed charge, an alternative to would be to make a determination as to what portion of a customer's bill it is reasonable to collect through fixed charges, in particular in the case of low-use customers. As MGE has committed to work with CUB and other interested parties on rate design concepts for a 2016 test-year filing, the Commission may wish to consider providing guidance as to what issues it would like to see explored in that collaborative process related to fixed charges, and what principles should guide fixed charge rate design.

Q. Could you please comment on why you limited the increase in fixed charges to 20 percent for Residential, small commercial (Cg-5, Cg-3), and Cg-4 customer classes, rather than setting them at the levels suggested by your analysis?

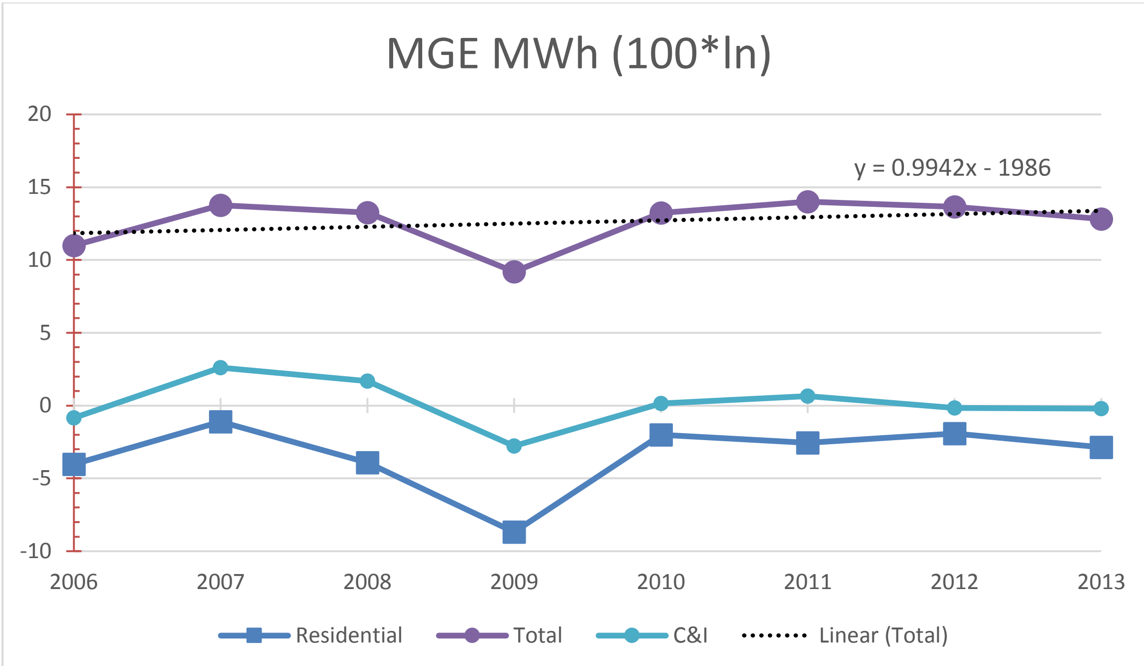
A. For these customer classes, fixed charges such as the customer charge make up a larger percent of the class revenue than is the case for larger customer classes. As such, increases in fixed charges for the residential, small commercial, and Cg-4 customer classes would have a disproportionately larger effect on lower energy use customers within each class. In MGE's last full rate case, docket 3270-UR-118, the Commission limited increases in fixed charges to 20 percent. Using that as guidance, I similarly limited the increase in this proceeding to 20 percent for the residential, small commercial, and Cg-4 customer classes. Larger customer classes see a much smaller portion of their overall bill collected through fixed charges. In light of this, my adjustments to Mr. James's proposed fixed charges were more modest, seeking instead to limit fixed charge increases to approximately 40 percent.

A common rate design principle is that of gradualism and a desire to avoid rate shock when adjusting utility rates. I believe that the percentage increases I have proposed for residential and small commercial fixed charges allows for a more gradual approach, while still allowing for more deliberate movement towards a desired fixed charge level. For example, were the Commission to determine that $17.43 is a reasonable target level for residential fixed charges, but that 20 percent represents an upper limit for a single increase to those charges, it would it would only take four rate cases, including this one, to set fixed charges equal to a cost based value.

Q. Do you believe that scenario represents a reasonable transition timeline for fixed charges?

A. At its core, MGE's argument in favor of higher fixed charges is based on the fact that part of the revenue from utility variable charges go towards covering fixed costs. From the utility's perspective, MGE then under-recovers fixed costs from low energy purchasing customers. If one then makes the assumption that there is a reasonable likelihood of negative sales growth in the future, it becomes evident that lower fixed charges expose the utility to increased risk. Increasing the fixed charges then is a means by which to decrease the utility's exposure to risk from decreased sales.

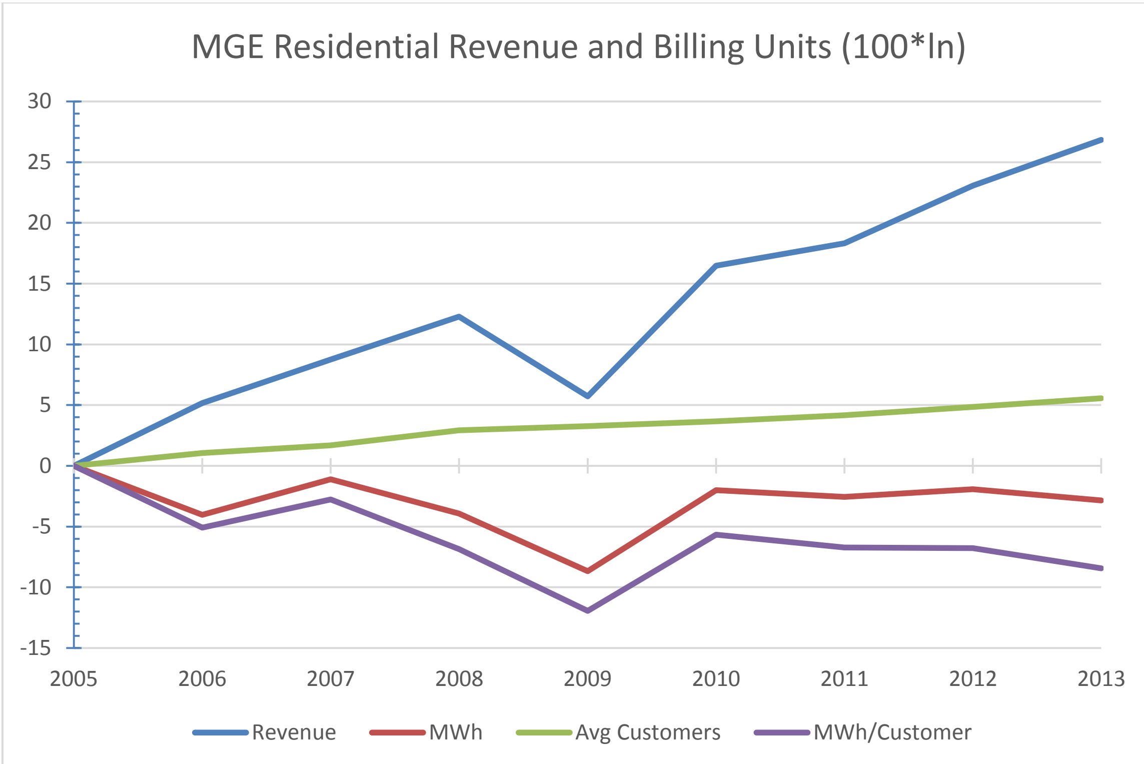
This begs the question of how much risk the utility is exposed to over time. Considering the period from 2006 through 2013, MGE's total energy sales have essentially been flat, with 2013 MWh sales only about 1.8 percent higher in log terms than 2006 levels. Using a linear regression over the entire 2006-2013 period, we can estimate that MGE has on average seen only 0.2 percent annual increases in electricity sales. The figure below illustrates this.



When one considers the fact that Wisconsin utilities receive the benefit of a number of risk mitigation measures, including forward looking test years, opportunities for biennial (if not annual) base rate cases, cost of fuel adjustments, and a variety of escrow treatments, this trend in sales hardly seems to present a great deal of risk to the utility's ability to recover its costs while still having a reasonable opportunity to return on its investments. In fact, assuming test-year sales forecasts are, on average, reasonably accurate, MGE is really only exposed to sales risk in the second year the utility is out between cases. This of course assumes that the utility does not come in each year. In the end, there does not appear to be an urgent need to dramatically change MGE's rate design over only one or two rate cases. Similarly, while MGE witnesses have expressed concerns about the future, I do not believe the company has presented adequate evidence to suggest that haste is in order.

For example, the effect that future distributed generation (DG) penetration rates may have on utility revenue and cost recovery is one issue that all electric utilities currently face. Experiences in this area currently being borne out in California and the American southwest certainly gives one pause. However, if one were to consider the composition of MGE's customer base, it seems likely that MGE's experience with DG would unfold very differently. MGE's service territory is predominantly urban and suburban, meaning that MGE customers face significant physical constraints with respect to siting DG installations. Additionally, information supplied by the utility (Schedule 2 of Ex.-PSC-Singletary-2) suggests that approximately 55,000 of the utility's 125,404 residential customers are apartment dwellers. This means that a little less than half of MGE's residential electric customer base has a significantly diminished incentive to invest in DG. Those rental unit customers do not own the premises, and therefore would likely see little benefit in investing in DG or energy efficiency devices that would become fixtures effectively permanently attached to the rental dwelling.

Now, it is true that MGE, like most Wisconsin utilities, has seen an overall trend in decreasing per-capital usage of energy. Since 2005, MGE's average residential per-capita use has fallen by about 8.4 percent in log terms. This trend has been noticeably flatter as of late but historical data does seem to suggest some slight downward trend. The figure below illustrates this. However, as I noted previously, this trend appears to suggest that the near- to mid-term risk from sales loss is minimal. Considering all of this, while some action may need to be taken by MGE in the future to address DG integration and the impacts of decreasing per-capita energy usage and DG integration, I believe that a more measured approach, guided by deliberate and thoughtful policy decisions on the part of the Commission is the most reasonable course of action.



Q. Could you please comment on your proposed grid connection charge for residential and small commercial customers?

A. The $2.09 grid connection charge I have proposed for residential and small commercial customers is equal to 20 percent of the current customer charge. Customer charges for residential and small commercial classes are kept flat in my proposed rate design and the 20 percent overall increase in fixed charges is achieved through the institution of the new grid connection charge.

Q. Please comment on your proposal to remove the Rg-7, Cg-7, and Cg-8 DG rate classes proposed by MGE.

A. Yes. My understanding is that the utility proposed these rates as a means by which to moderate the impact the utility's proposed fixed charges would have on existing distributed generation customers. Due to the significantly smaller increase to fixed charges under my proposed rate design, I believe that these new tariff offerings may not be necessary at this time. Again, in light of the rate design collaborative that will be occurring in the coming months, and given that distributed generation customers will likely be affected by any innovative rate design coming out of that collaborative, I believe it may be more prudent to hold off on instituting any new DG rates until all parties have a clearer picture of what future rate designs might look like. As with my prior suggestion related to fixed charges, the Commission may wish to consider whether to issue any specific guidance or identify any areas of concern related to DG rate design so as to better inform the parties participating in the rate design collaborative.

Q. Please comment on your proposal to remove the Rg-6 low income rate option proposed by MGE.

A. It is my understanding that two concerns motivated the utility to propose the Rg-6 low income rate option. First, there were concerns regarding regressive bill impacts to low-use, low-income customers resulting from the utility's originally filed rate design proposal might impact. Second, the utility has proposed to eliminate the Rg-3 lifeline rate. In either case, the Rg-6 rate offering would provide an option for low income customers who might otherwise see significantly higher than average increases.

First, with respect to the elimination of the Rg-3 Lifeline rate, I do not have any strong objections to MGE's proposal to cancel the Lifeline rate in this proceeding. Doing so and transferring all Rg-3 customers to the standard Rg-1 rate would produce, on average, a 62 percent increase in rates for these customers. That being said, it has been the Commission's intent to phase out MGE's lifeline rate and transition those customers to a standard rate offering over the course of a number of proceedings. Now may be the appropriate time to finally move customers off the Lifeline rate, recognizing that that final step, whether it occurs in this or a future proceeding, may unavoidably entail disproportionately large rate impacts when the final transition is made.

Second, as the utility has moderated its proposed rate design for this rate case, I believe that there is no longer a compelling need to protect low-income customers from large bill impacts in this proceeding. Having said that, if the Commission elects to not approve MGE's currently proposed Rg-6 low-income rate in this proceeding, the Commission may wish to consider whether to direct that low income rate design proposals be considered in the rate design collaborative.

Q. Do you have any other comments regarding the Rg-6 low income rate?

A. Yes. As noted, my decision not to institute a new low income rate design at this time is predicated upon a smaller increase to residential fixed charges than that proposed by Mr. James in his second supplemental direct testimony. In addition, I also have some concerns that a low income rate may be considered discriminatory. That being said, if the Commission chooses in this proceeding to authorize residential fixed charges closer to the $19 level proposed by Mr. James, the Commission may wish to consider whether it is also reasonable and/or equitable to also institute a low income rate option like MGE's proposed Rg-6, and if so, whether the rate as proposed requires any modification so as to be consistent with state law.

Q. Have you proposed any changes to MGE's voluntary renewable energy rate, marketed as the Green Power Tomorrow (GPT) program?

A. Yes. In MGE's last full rate case, the Commission increased the GPT rate from $0.025 to $0.040 per kWh. Since that time, the Commission and Commission staff have had the opportunity to more thoroughly examine the renewable premium calculation methodology for Northern States Power Company-Wisconsin (NSPW) in dockets 4220-UR-118 and 4220-UR-119. Based on that experience, I revisited the calculation methodology for the GPT premium rate. Using GPT production supply cost data provided by MGE, and a calculation method consistent with the one approved by the Commission for NSPW, I have estimated the GPT premium to be $0.0244 per kWh. I am proposing that the RWE-1 and BWE-1 rates be reduced to $0.0244 per kWh for the test year. This calculation and associated revenue calculations can be seen on pages 14 to 16 of Ex-PSC-Singletary-1, Schedule 1.

Q. Your proposed rate design does not reflect this proposed change to the GPT premium. Could you please explain why that is?

A. Yes. The revenue collected from the GPT program is allocated to all customers in the COSS on an energy basis. As such the most accurate way to reflect a change the GPT rate would be to adjust GPT revenue in the COSS. This would produce different class retail revenue deficiencies which could be used as the basis for revenue allocation. I did not do this as I was concerned that doing so might cause confusing situations where values in the COSS did not match income statement values from audit staff. In order to allow the Commission to consider COSS and GPT as two separate decision points, I have provided an estimate of the rate impact to each class if the GPT rate were to be adjusted as I have proposed. This can be seen in the far right columns on page 1of Ex.-PSC-Singletary-1, Schedule 2. Since GPT revenue is allocated on the basis of energy in the COSS, I am proposing that the revenue impact of any GPT rate change also be allocated back the classes on an energy basis.

Q. Does this conclude your direct testimony?

A. Yes.

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