Public Service Commission of Wisconsin
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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates

Docket No. 5-UR-110

DIRECT TESTIMONY OF COREY S.J. SINGLETARY ON BEHALF OF CITIZENS UTILITY BOARD

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

A. My name is Corey S.J. Singletary and my business address is the Citizens Utility Board (CUB), 625 North Segoe Rd, Suite 101, Madison, Wisconsin 53705. I am employed by CUB as Director, Regulatory Affairs.

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 with a Graduate Certificate in Energy Analysis and Policy from the University of Wisconsin–Madison, and am a member of the Pi Alpha Alpha Honor Society for Public Affairs & Administration. I have completed training courses in public utility regulation at the Michigan State University Institute of Public Utilities and the New Mexico State University Center for Public Utilities. From May 2010 through June 2017, I was employed by the Public Service Commission of Wisconsin. During my time with the Commission, my work focused on, but was not limited to, electric and natural gas utility cost allocation and rate design, as well as a number of policy issues such as smart grid technology, innovative rate design, rate-based energy efficiency, conservation, demand response programs, and distributed energy resources.

Since 2017 I have worked for CUB as a rate and policy analyst, and most recently as Director, Regulatory Affairs where I oversee and coordinate the consumer advocacy work conducted by CUB staff before the Commission and in other venues.

Q. Have you testified before this Commission before?

A. Yes. I have testified in roughly 60 electric, natural gas, and water utility proceedings before this Commission.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of CUB.

Q. What is the purpose of your direct testimony?

A. The following issues as presented by in the direct testimonies of the Applicants' witnesses:

1. Utility Return on Equity
2. Other Revenue Requirement Issues
3. Electric Utility Cost Allocation
4. Electric Utility Revenue Allocation
5. Electric Utility Rate Design
6. Natural Gas Cost Allocation
7. Natural Gas Revenue Allocation
8. Natural Gas Rate Design

Utility Return on Equity

Q. Can you please summarize your testimony regarding the applicants' test year return on equity (ROE)?

A. Yes. My testimony and that of Dr. Kihm are two parts of a whole, where utility ROE is concerned. Dr. Kihm approaches ROE from a technical perspective, leveraging his decades of experience in utility finance. My testimony builds on this technical foundation. Specifically, I apply the appropriate public policy framework to his estimate of the Applicants' cost of equity to arrive at CUB's recommended test year ROE.

Q. To begin, can you define policy analysis?

A. Yes. The following is from Weimer and Viding's *Policy Analysis*, which is a leading text in the field (Weimer is at the University of Wisconsin):

> *Policy analysis* is <u>client-oriented</u> advice relevant to <u>public decisions</u> and informed by <u>social values</u>.[1] (Italics in original; underlines added.)

In this proceeding, CUB represents a particular client base, namely, residential and small business customers (the vast majority of customers); the determination of utility ROEs rests with a public agency, namely, the Public Service Commission; and, as will be discussed below, the U.S. Supreme Court tells us that the ROE determination requires balancing customer and investor interests in a public setting. Thus, policy analysis is at the heart of this proceeding.

Q. Are you an expert in public utility or corporate finance?

A. No. I am an expert in policy analysis, as just described. I defer to Dr. Kihm on matters strictly of a finance nature. The cost of equity is a finance variable; the ROE is a policy choice. See Dr. Kihm's testimony. I have spent the entirety of my professional career developing a deep understanding of public utility regulation and utility ratemaking, having worked on, in some fashion, nearly every investor-owned utility (IOU) rate proceeding over

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[1] David L. Weimer and Aidan R. Vining, 2011, *Policy Analysis: Concepts and Practice*, London: Pearson Longman, p. 24.

the last 12 years. I possess extensive expertise in public policy as it relates to the regulation of public utilities. My core expertise is in utility ratemaking, particularly cost allocation and rate design. Beyond simply "pushing numbers" on a spreadsheet, utility ratemaking involves balancing the needs and interests of various utility customer classes, the utility, and sometimes stakeholders external to the public utility industry. In my current role with CUB, I advocate on behalf of residential and small business customers. However, during my time as Commission staff, my job was to consider and balance the needs of all utility customers. Additionally, beyond utility rates, I have spent much of my career working on and testifying regarding regulatory issues more policy in nature. It is this expertise that I bring to the discussion of utility ROE.

Q. Please elaborate.

A. Certainly. But first, I would like to set the stage.

When considering the question of utility ROE, the landmark U.S. Supreme Court decisions *Hope*[2] and *Bluefield*[3] are commonly referenced as "establishing the standards for determining a fair and reasonable authorized ROE." (Direct-WEPCO/WG-Bulkley-3) Through these decisions, the Supreme Court has indicated that "the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests."[4] Indeed, in the last IOU rate proceeding where this Commission decided on authorized ROE as a litigated issue, the Final Decision states:

> In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers, with due

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[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").
[3] *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").
[4] *Hope,* 320 U.S. 591 at 603.

> considerations to economic and financial conditions, along with public policy considerations.[5]

Even Ms. Bulkley notes in her direct testimony that "[r]egulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers." (Direct-WEPCO/WG-Bulkley-51)

All of this – the balancing of interests between customers and investors – clearly frames utility ROE as a public policy problem, not a finance problem.

When considering this balance between utility customers and investors, the Commission has provided guidance by stating that:

> Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of reasonable expectations.[6]

I disagree with the Commission regarding the issue of capital attraction, for the reasons discussed in Dr. Kihm's testimony. However, in this order the Commission indicates that setting a utility's authorized return equal to the investor's "required return" fully compensates investors, and any return set in excess of the "required return" represents "windfalls to utility investors." Viewed through the lens of a policy analyst, the foregoing suggests that if the task is to set an authorized ROE that reasonably balanced the interests of investors and consumers, a reasonable starting point would be the investor's "required return." This return would, as the Commission notes "compensate providers for the risks

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[5] *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, Docket 4220-UR-123, Final Decision, Served December 21, 2017 (PSC REF#: 335158)
[6] *Id.*

they face when providing funds to the utility."[7] As discussed in Dr. Kihm's testimony, this "required return" is equal to the utility's cost of capital. More specifically as it relates to ROE, we are looking for the utility's *cost of equity*.

Q. **Do you have an estimate of the applicants' test year cost of equity?**

A. Yes. As discussed by Dr. Kihm, the utility test year cost of equity is estimated between 6 percent and 7 percent.

Q. **Is it your position that the Commission should set the applicants' authorized ROE equal to the estimated cost of equity?**

A. No. As discussed by Dr. Kihm, the ROE could be set equal to the cost of equity, but in many cases that might not be the best policy. More than that however, I believe it is important to maintain the distinction between ROE and the cost of equity as two distinct returns. In my experience, people often slip in representing ROE and cost of equity as being interchangeable. I would like to avoid the hazard of arriving at the faulty conclusion that the ROE should or must equal the cost of equity.

Q. **Let's return to the issue of balancing customer and investor interests. Previously, you characterized finding the cost of equity as a "starting point." Setting aside that you've already said that you don't believe the Applicants' ROE should be set equal to the cost of equity, what would you say regarding that balance if Applicants' ROE were set equal to the cost of equity?**

A. If the authorized ROE were set equal to the cost of equity, I would say that the balance would clearly be shifted toward the customers' interests. However, this would not represent a shift to the detriment of new utility investors. As discussed by Dr. Kihm, if a utility's ROE

[7] Id. (?)

is equal to the cost of equity, the investors' needs are covered. It would not make WEPCO stock particularly attractive to prospective investors, but it meets the investors' minimum requirements. The utility is essentially treading water, as Dr. Kihm discusses, and is not creating value for its existing investors. However, what this hypothetical scenario suggests to me is that the Commission must consider whether there is a "fair" balancing of customers and shareholders when awarding an authorized ROE. Under the "ROE equals cost of equity" hypothetical, the balance is shifted as far in the customers' direction as it can go before utility investors are "harmed" in the sense that they are insufficiently compensated for the risk of their investment. There is, however, a more significant fairness issue here. Pushing the ROE all the way down to the cost of equity would cause significant capital losses for WEC Energy Group's present investors—the shareholders. As Dr. Kihm explains, those are the interests the Commission must balance against consumer interests. In effect, one could consider the cost of equity as a floor for ROE. Then, as the ROE increases relative to the cost of equity the balance shifts in the utility investors' favor.

Q. You noted that utility investors are fully compensated, made whole if you will, if the ROE is set equal to the cost of equity. Are customers harmed if the ROE is set greater than the cost of equity?

A. Assuming nothing changes about the service provided to utility customers, then yes. As the "delta" between an increasing ROE and the cost of equity increases, customers are harmed in the sense that they pay increasingly higher rates for their utility service without receiving any incremental benefits commensurate with the increased ROE cost. Put another way, setting the ROE in excess of the cost of equity reduces the value proposition for the customer unless that increased ROE is accompanied by a commensurate increase in the value of the service received by the customer. This is the central tension in any discussion of utility authorized ROE.

Q. Considering this tension, is there a quantitative method for determining an appropriate authorized ROE that might simplify the process?

A. If the question if whether there is a formula to determine ROE, similar to how one could use the discounted cash flow (DCF) or capital asset pricing model (CAPM) to estimate the cost of equity, then the answer is no. There is no ROE formula, not as it relates to setting authorized returns on equity for regulated utilities. In fact, if we circle back to *Bluefield*, the Supreme court opined that "It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts."[8] This makes it clear that ROE comes down to a public policy decision and "judgment" on the part of utility commissions.

Ultimately, I believe, and it is CUB's position that setting a utility's authorized ROE should be considered as a two-step process. First the Commission should determine a reasonable estimate of the utility cost of equity, using quantitative methods as discussed by Dr. Kihm. This, as I have already discussed, can be used as a "floor" for the authorized ROE. From there, the Commission should apply a public policy lens as it considers the balance between the customers and utility investors (present investors) in its awarding of any return premium in excess of the cost of equity.

Q. Does CUB have a recommendation for how the Commission should approach this second step?

[8] *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*")

A. Yes. Ultimately it's about finding that "fair" balance of customer and investor interests. Is the utility being awarded an ROE commensurate with its customers' value proposition? Or is the utility receiving a rich premium over the cost of equity simply for being a utility – for simply showing up for work as it were.

Dr. Kihm discusses it in his direct testimony, but it bears repeating. Alfred Kahn writing in *The Economics of Regulation* states that:

> Merely permitting all regulated companies as a matter of course to earn rates of return in excess of the cost of capital does not supply the answer; there has to be some means of seeing to it that those supernormal returns are *earned*, some means, for example, of identifying the companies that have been unusually enterprising or efficient and offering the higher profits to them while denying them to others.[9] (Emphasis in original.)

As it considers returns above the cost of equity, the Commission should not view the exercise as being aimed at compensating investors for risk— the cost of equity (investors' required return) completely addresses the risks investors face. Instead, the Commission should consider the magnitude of the ROE premium (above the cost of equity) to be earned based on how well applicants treat their customers. An ROE in excess of the cost of equity should be considered a performance reward with the ROE for poor performing utilities tending toward the cost of equity and excellent performing utilities receiving a larger ROE premium. Again, utility performance should be evaluated from the customer's perspective.

Q. How should the Commission evaluate a utility's performance?

A. In my opinion, when making decisions regarding authorized ROE the Commission should evaluate utilities across a consistent set of performance areas, using quantitative metrics where possible. This would allow the Commission to easily gauge utility performance,

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[9] Alfred Kahn, 1970; 1988, *The Economics of Regulation: Principles and Institutions*, Cambridge, MA: MIT Press, p. 54.

whether in isolation or in comparison to other Wisconsin utilities or other utilities around the country. This would also allow for consistency from one rate proceeding to another which provides transparency into the decision-making process and gives the customers, the utility, and utility shareholders a degree of certainty.

Q. Can you give examples of what performance areas or metrics the Commission should consider?

A. To start, the Commission should consider standardized metrics for utility operations, with a goal to evaluate utility performance against the three "legs" of utility regulation: Safety, Reliability, and Affordability. For example, the Commission should evaluate utility reliability using the standardized metrics of SAIFI, SAIDI, and CAIDI.[10] For safety, the Commission could review data regarding safety violations or instances where injuries or property losses occurred as a product of utility operations. For affordability, the Commission could compare the cost of a utility's service to that of other utilities, as well as evaluate any trends in that cost over time. To evaluate the customer experience, the Commission should consider metrics such as performance in resolving complaints and customer satisfaction scores.

These examples represent merely a starting point. There are several performance areas with traditional measurements, as well as new utility performance areas, that could be used to evaluate utility performance. The table below provides additional examples of the types of utility performance metrics that could be used by the Commission when evaluating utility performance. I

[10] System Average Interruption Frequency Index (SAIFI) is the average number of interruptions that a customer would experience. System Average Interruption Duration Index (SAIDI) is the average outage duration for each customer served. CAIDI gives the average outage duration that any given customer would experience. CAIDI can also be viewed as the average restoration time. All of these reliability indices are typically measured over the course of a year

have also included a copy of the 2021 Utility Performance Report prepared by the Citizens Utility Board of Michigan (CUB MI Report) as Ex.-CUB-Singletary-1. This report examines the performance of Michigan's electric and natural gas public utilities across a variety of metrics.

Performance Area	Performance Metric
Reliability	Generator reliability
	SAIFI
	SAIDI
	CAIDI
Affordability	Disconnections
	Low- to middle-income (LMI) energy burden
	LMI program utilization
	Payment arrangement availability
	LMI voluntary energy efficiency (EE) participation
	LMI Voluntary EE savings
Cost Control	Annual Revenue Growth
	Operational Expense vs. Budget
	Capital Expenses vs. Budget
	Enterprise Protection Risk Management
	O&M cost per customer
	Rate base per customer
Customer service	Customer Satisfaction
	Average length of time to resolve customer complaint appeals
	Number of customer complaints appealed by customer class
	Number of formal customer complaints
	Average time to respond to service and outage complaints
	Average time to resolve billing disputes
	Call Center Performance
	Wait time in commercial offices
	Interconnection Time
	Reconnection time
Customer Engagement	Time of Use (TOU) participation
	Utility Program participation
	Customer meter data accessibility (e.g. Green Button Connect)
Grid Investment Efficiency	Avoided Transmission and Distribution (T&D) investment

DER[11] Asset Effectiveness	Advanced grid services Advanced Metering Infrastructure (AMI) utilization Demand Response Capacity Demand Response Utilization

The table above and the CUB MI Report include many performance metrics that I believe the Commission should consider when awarding an authorized ROE. The Commission could consider a small number of critical or high impact metrics. Or the Commission could consider many of these performance metrics, giving certain metrics greater or lesser weight depending on policy priorities.

Q. What types of performance criteria has the Commission considered when it has set utility ROE in the past?

A. Therein lies the challenge in Wisconsin. To my recollection, this Commission has never explicitly considered utility performance when it has awarded authorized utility ROE, at least not in this century.

As Dr. Kihm discusses in his direct testimony, the ROE-setting framework we have been discussing is not new. Despite decades of literature and legal precedent on the topic of utility regulation and ROE, state commissions have been slowly led astray from the fundamental ratemaking principles that 1) a just and reasonable authorized ROE must balance customer and utility shareholder interests; 2) ROE and cost of equity are two different measures; 3) an ROE equal to the cost of equity is sufficient to meet investors required returns; and 4) any ROE premium in excess of the cost of equity should be awarded based on a utility's performance with respect to the value of the service received by its customers, since the customers pay that premium.

[11] Distributed Energy Resource.

Over time, state commissions have been led to believe that a particular financial model will provide the answer to the question of what a utility's *ROE* should be. In fact if one reviews past Final Decisions by this Commission where it has ruled on ROE as a contested issue, one finds language such as:

> Based on its modeling, Commission staff suggested that a reasonable return on equity falls within a range from 9.60 percent to 10.00 percent…[12]

and

> The Commission finds that the models used to estimate the return on equity in this case indicate that a reduction from the currently authorized return on 10.20 is reasonable.[13]

The Commission will occasionally include mention of other utility risk factors such as:

> factors such as forward-looking test years, annual rate cases, and higher levels of fixed charges, mitigate some risk[14]

The recurring thread is that models will *provide* the ROE to the Commission.

Some of this shift is likely attributable to understandable error, as people will often conflate cost of equity and ROE and use the two terms interchangeably. However, I believe that a second, more significant driver of this shift is the ubiquitous proliferation of flawed utility ROE analysis as is discussed by Dr. Kihm. For example, refer to the quote above. The Commission appears to be considering company-specific risks in setting ROE. Investors do not need compensation for those risks as costs of equity. Why does the utility need compensation for them as ROE? See Dr. Kihm's testimony.

[12] Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates, Docket 4220-UR-123, Final Decision, Served December 21, 2017 (PSC REF#: 335158)
[13] Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Docket 6690-UR-124, Final Decision, Served December 17, 2015 (PSC REF#: 279522)
[14] Id.

Q. While CUB's recommendation for an ROE setting framework is not new *per se*, would you agree that Commission adoption of CUB's proposal would represent a deviation from recent practice?

A. Absolutely, yes.

Q. Can you please explain why you believe it is reasonable that the Commission make this change now?

A. Yes. This proceeding marks the first time the ROE of WEPCO and WG is being presented to the Commission as a contested issue in *thirteen years.* Specifically, the last time the Commission ruled on Applicants' ROE outside of a settlement agreement was in 2012, Docket 5-UR-106; however ROE was not raised as an issue in that proceeding. One must go back to 2009, in Docket 5-UR-104, to find the last time the Commission ruled on Applicants' ROE as a contested issue, with all of the extensive record evidence that accompanies such. Much has changed since that time, which I believe in and of itself begs for a fresh look at issues. More important, however, is that in recent years the Commission has signaled, through its discussions of record regarding numerous rate case settlements, that it has a strong interest taking a fresh and detailed look at a number of regulatory issues, whether it be customer fixed charges, stranded asset recovery, or ROE. Moreover, the Chairperson has indicated publicly that utility affordability, as well as equity, are key concerns for her and the Commission. The macroeconomic concerns that Ms. Bulkley says are affecting IOUs, "(1) changes in monetary policy, (2) currently high inflation continuing into 2022, (3) increasing interest rates, and (4) volatile market conditions" (Direct-WEPCO/WG-Bulkley-12-13), are also affecting customers, especially low- to middle-income customers whose monthly budgets can be tight. If one is concerned about affordability, a utility's ROE is the strongest financial policy lever at the Commission's disposal, not only to control overall revenue requirements, but also to influence a utility's financial incentives in favor of beneficial outcomes for customers.

Considered together, this proceeding presents a compelling argument in favor of taking a fresh look at ROE, with an emphasis on a return to the core finance principles discussed by Dr. Kihm.

That being said, even if the context for this proceeding were unremarkable, I believe that the evidence presented by Dr. Kihm clearly shows that Applicants' requested ROE of 10.0 and 10.2 percent for WEPCO and WG are far too high, and provide the utility with a significant premium in excess of its cost of equity at the expense of Applicants' customers.

Q. Would you agree that core theme of your testimony regarding ROE is that a utility's authorized ROE should reflect explicit consideration and judgment of a utility's performance?

A. Performance as measured from the utility customer's perspective, yes.

Q. Are you aware that the Commission is currently explore the issue of performance based regulation (PBR) through a series of ongoing workshops?

A. Yes, I am.

Q. Are you suggesting the Commission adopt PBR in this proceeding?

A. No.

Q. Please explain.

A. PBR, as that term is currently used, refers to a regulatory framework that explicitly ties certain ratemaking outcomes to specific utility performance. With respect to utility ROE, PBR almost always envisions a set of performance incentive measures that can provide rewards or penalties through changes in a utility's authorized ROE based on specific metrics or utility behaviors. In this sense, PBR applies a more formulaic approach to the intersection of utility performance and ROE. That is not what CUB is suggesting here.

What I and Dr. Kihm are proposing here is a return to fundamental finance and regulatory principles. Application of the framework we are recommending does require that the Commission explicitly tie "X% of ROE to Y% change in metric Z." The Commission could apply our recommended framework through a subjective consideration and discussion of the various aspects of utility performance that led it to conclude that some return premium in excess of the cost of equity is reasonable.

Regardless of what performance criteria the Commission uses to set a utility's ROE, what is critical is that the Commission do the following:

1. Explicitly articulate what performance criteria it considered in arriving at an authorized ROE; and
2. Explicitly articulate how a utility's performance against those criteria affected the final authorized ROE.

These steps are important, not only for transparency, but because they provide a clear performance signal to the utility so that it can be afforded a reasonable opportunity to improve its performance over time and thus to be awarded a higher ROE. Moreover, I believe that only through this process can we satisfy the public policy need that the interests of customers and utility shareholders be balanced, as established by the Supreme Court. But ultimately, these steps need not be formulaic as is contemplated in modern discussions of PBR.

Q. Is there any intersection between what CUB is proposing in this proceeding and PBR?

A. Yes. To the extent that any PBR framework explored or implemented in Wisconsin includes incentives tied to ROE, it is critical that the Commission adopt the "bottom-up" approach to setting utility ROE. If this is not done, and PBR incentives are applied on top of an already inappropriately high ROE, all Wisconsin will have accomplished is providing a windfall to utility shareholders in exchange for little to no improvement in the value proposition for utility customers. In short, CUB is not proposing PBR in this proceeding. However, if the Commission wishes to explore implementation of PBR, adoption of CUB's recommended ROE framework is a necessary pre-condition. Moreover, if the Commission adopts CUB's recommendation but ultimately declines to implement a formal, modern, PBR framework, nothing will be lost. Adoption of CUB's recommended ROE framework is simply a no-regrets alternative from the customer's perspective.

Q. Have you performed an analysis of any utility performance metrics for the purposes of this proceeding?

A. Yes. For the purposes of this proceeding, I collected and examined data related to the following customer-facing performance areas:

- Customer electricity utility rates (Ex.-CUB-Singletary-2)
- Utility Reliability (Ex.-CUB-Singletary-3)
- Customer satisfaction (Ex.-CUB-Singletary-4)

Q. What data did you use to conduct your analyses?

A. In developing my comparison of electric utility rates and utility reliability, I used annual data reported to the U.S. Energy Information Agency (EIA) via its Form EIA-861. In looking at utility rates, I took a snapshot of the most recent decade of finalized data, which covers the period of 2011-2020. For utility reliability I looked at the period starting in 2013, the first year EIA began collecting reliability data in Form EIA-861, through 2020. For customer satisfaction, I collected publicly available data from the J.D. Power Electric Utility Residential Customer Satisfaction Study for the years 2015-2021.

Q. What did your analysis of electric utility rates reveal regarding applicants' performance?

A. The analysis I performed is similar to that done by Commission staff as part of the biennial Strategic Energy Assessment, so the following results are not revelations. However, upon review I determined that WEPCO's effective cost of electricity ($/kWh) ranks second highest among Wisconsin IOUs. WEPCO has held that ranking since 2012. Prior to that, in 2011, WEPCO was the most expensive electric IOU in Wisconsin when considered on an effective $/kWh basis. If one considers just the residential class of customers, the picture does not improve as WEPCO's residential electric customers have also paid the second highest effective rates in Wisconsin for the entire period examined. Additionally, it is important, to consider that the state of Wisconsin as a whole has ranked second highest among Midwest states in the price of electricity for the entirety of the period examined, falling behind only the state of Michigan.

Q. Did you evaluate any trends in WEPCO's electricity rates over time?

A. Yes. I looked at the compound annual growth rate (CAGR) of electricity rates over the 2011-2020 period and determined that WEPCO rates have experienced the third and second highest growth rates, when considering the utility as a whole or just the residential class, respectively.

Q. What did your analysis of electric utility reliability reveal regarding applicants' performance?

A. For reliability I developed state-level values across the reported reliability metrics of SAIFI, SAIDI, CAIDI, both with major event days (MED)[15] and without, using a weighted average approach. I also extracted reliability data for WEPCO and developed an average for the state of Wisconsin, exclusive of WEPCO. I then calculated the three year rolling average for all of these values to smooth year-to-year volatility. Additionally, I developed single-year comparisons of Wisconsin's performance against other states across the same metrics for the years 2018-2020.

When compared against its Wisconsin peers, WEPCO shows signs of improving reliability across all three metrics. In the case of SAIFI and CAIDI, this improvement represents a trend which brings WEPCO in line with the average of other Wisconsin utilities. It is only in system average duration *inclusive* of MED, that WEPCO has started to slightly outperform other Wisconsin utilities, which suggests that WEPCO's storm restoration performance has improved over time whereas other utilizes have trended in a slightly negative direction, when considered in aggregate.

As noted previously, I have also provided single year snapshot comparison of the state of Wisconsin compared to other states across these metrics. Trends are more difficult to tease out. But in general, Wisconsin has fared well against other states when evaluating utility system outages.

Q. What did your analysis of utility customer satisfaction reveal regarding applicants' performance?

[15] Major event days are typically caused by severe weather. The IEEE definition of an MED is "Designates a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24 hour period." IEEE Standard 1366

A. J.D. Power and Associates considers WEPCO to be a Large electric utility within the Midwest region. For my analysis I prepared a comparison of WEPCO against other Wisconsin IOUs, as well as the average of other large electric utilities in the Midwest, on a raw score basis. Additionally, I prepared a ranked order comparison of WEPCO against other Wisconsin IOUs (with 1 being the highest score), as well as other large Midwest electric utilities.

Q. How does WEPCO fared in this customer satisfaction analysis?

A. I believe it would be fair to say that WEPCO's residential electric utility customer satisfaction scores have been unremarkable over the 2015-2021 period. This is the case whether one is comparing WEPCO against its Wisconsin peers or Midwest utilities of comparable size - WEPCO's scores fall near or slightly below average in most years.

Q. How do you proposed that the Commission use these metrics to determine an authorized ROE for the applicants?

A. The preferred approach would be the application of the framework discussed in the testimony of Dr. Kihm and myself. The Commission should start with a reasonable estimate of the utility cost of equity using valid quantitative methods that are supported by the financial literature and the corporate finance industry at large. This then serves as the "floor" or starting point where investors' required return is covered. From there, any premium awarded to the applicants in excess of the cost of equity should be determined based on utility performance with respect to the utility's customers, the service received by those customers, and whether the utility provides a value proposition for its customers. The costs of an incrementally higher ROE should be commensurate with the incremental benefit received by customers.

However, the challenge I acknowledge is that a transition period will likely be required before the Commission can eventually implement the ROE process as it was originally designed. In light of this, and based on the evidence presented by Dr. Kihm, CUB is recommending the Commission authorize a test year ROE of 9.0 percent for WEPCO and WG.

Q. Dr. Kihm presents considerable quantitative evidence in support of an ROE of 9.0 percent. Is that ROE consistent with your examination of ROE from a public policy perspective?

A. Yes. Based on my review of a limited set of metrics, I would characterize WEPCO's past performance as merely average. On the reliability front WEPCO has achieved gains over time. While those improvements have served to merely bring WEPCO in line with the average of other Wisconsin utilities, I do note that Wisconsin as a whole appears to fare slightly better on reliability metrics than average when compared to other states. This is offset by WEPCO's average cost of electricity, which viewed either in total or from the residential customer's perspective, remains high among IOUs – second highest in a state that ranks second highest in the region. And as noted previously, WEPCO's customer service rankings are generally unremarkable.

This assessment is consistent with my subjective ex-ante expectations, as prior to this proceeding I would have described WEPCO as a utility as "fine." That said, fairness looms large when setting the ROE. Consumers are paying too much for utility service, so a reduction in ROEs is necessary. Reducing ROEs to 9.0% will likely cause capital losses for WEC Energy Group's present investors. To pretend that it won't is unrealistic. But the presence of capital losses does not mean that the regulatory action is invalid, as per the

Court. To obtain noticeable relief for customers requires noticeable capital losses for investors.

Q. Do you believe that the metrics you considered provide a full picture of WEPCO's performance?

A. No. For example, I would prefer, and recommend that the Commission adopt, a review of census-tract-level household burden data, both to consider whether WEPCO is adequately managing affordability and energy insecurity issues within its own service territory, and to compare performance against other utilities. While the Commission's Draft SEA suggests that such data exists for all Wisconsin utilities, it is not publicly available in a consistent, usable data format. I would also prefer that consideration be given to metrics regarding utility disconnections in order to evaluate any issues related to the availability of utility service, separate from system reliability, that are driven by economic hardship, inability to pay, and WEPCO's rising utility rates. But again, as with energy burden data, the availability of public data in a consistent, usable data format is an issue. While I am aware that utilities provide data regarding utility disconnections on the Commission's Electronic Regulatory Filing (ERF) system, the accessibility of that data is a barrier to meaningful use of the information provide by Wisconsin utilities for ratemaking purposes. Similarly, I believe it would be valuable for the Commission to consider the number and type of complaints made against Wisconsin utilities as well as information regarding the ultimate disposition of those complaints. Again, data availability is an issue despite existing reporting requirements on ERF.

These are merely examples of the core customer-focused performance areas I would recommend the Commission consider when evaluating utility performance. Moreover, it is likely that other utility customers or customer groups will have their own perspective on what is important.

Q. Is there any other evidence that would support CUB's recommended ROE of 9.0 percent during this transition period?

A. Yes. Dr. Kihm notes that the median earned utility ROE is 9.1 percent.[16] I must caution that this represents an inflated value due to the issues regarding utility authorized ROEs more generally, as discussed by Dr. Kihm. However, if one considers WEPCO to be an "average" utility, which I do absent any compelling evidence that the company is an exemplary performer, the median value is directionally consistent with CUB's recommended ROE of 9.0 percent.

Q. Considering everything we've already discussed, how do you view the applicants' currently authorized ROE of 10.0 percent for WEPCO and 10.2 for WG, which Ms. Bulkley has proposed to maintain?

A. The most obvious thing that jumps out to me is the 300 to 400 basis point delta between WEPCO's cost of equity and its requested ROE. This is a 42 to 66 percent premium over Dr. Kihm's estimated utility cost of equity.

Q. Have you reviewed the testimony filed by WEPCO witness Bulkley in support of the applicant's requested test year return on equity (ROE)?

A. Yes. In her direct testimony, Ms. Bulkley argues for maintenance of WEPCO and WG's currently authorized ROE of 10.0 percent and 10.2 percent, respectively. Upon review of her

[16] This is the average ROE at the holding company level. Authorized ROEs for regulated utility operations are closer to 9.5%. But many utilities do not earn their authorized ROEs, suggesting that the 9.1% may be a reasonable proxy for utility earned ROEs.

testimony, it is my understanding that she developed this recommendation based on a consideration of the following.

1. "the results of several analytical approaches to estimate the costs of equity for WEPCO and WG." (Direct-WEPCO/WG-Bulkley-3 to 4)
2. "company-specific business and financial risk factors to estimate the investor-required cost of equity for the Companies." (Direct-WEPCO/WG-Bulkley-4)
3. "the Companies' proposed capital structures for the test year in comparison to the capital structures of the utility operating subsidiaries of the respective proxy group companies." (Id.)

What is absent from Ms. Bulkley's testimony is any discussion of how her recommended ROE balances the interests of customers and utility shareholders. This, despite the fact that she makes reference to this balance in her direct testimony. (Direct-WEPCO/WG-Bulkley-51) In fact, a word search of Ms. Bulkley's direct testimony reveals that she uses the word "customer" or "customers" only nine times. Four of the nine come as part of her description of WEPCO and WG, specifically the number of customers the utilities serve. An additional mention comes as part of a description of how the Applicants earnings sharing mechanism works. The remaining uses I have copied below.

- "To the extent the Companies are provided a reasonable opportunity to earn a market-based cost of capital, neither customers nor shareholders are disadvantaged." (Direct-WEPCO/WG-Bulkley-8)

- "Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers." (Direct-WEPCO/WG-Bulkley-51)

- "Based on these results, the qualitative analyses presented herein, the business and financial risks of the Companies compared to their respective proxy groups, and current conditions in capital markets including the expectation for rising interest rates and increase in inflationary pressure, it is my view that an ROE of 10.00 percent as proposed by WEPCO and an ROE of 10.20 percent as proposed by WG are reasonable and would fairly balance the interests of customers and shareholders." (Direct-WEPCO/WG-Bulkley-62)

- "These ROEs would enable the Companies to maintain their financial integrity and therefore their ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable, and affordable electric and natural gas utility service to customers in Wisconsin." (Direct-WEPCO/WG-Bulkley-62)

The lack of any substantive discussion of the balance of customer and shareholder interests is striking to me. Yes, Ms. Bulkley does include brief mentions of capital attraction and borrowing costs as they may be affected by the utility's authorized ROE, and how that can affect overall revenue requirement. However, as discussed by Dr. Kihm, Ms. Bulkley's conclusions are predicated upon poor analytics and as such should be disregarded. As such, in my opinion the Applicants have presented no evidence regarding how its requested ROE balances customer and utility shareholder interests.

Q. Can you please summarize the specific actions you recommend the Commission take in this proceeding regarding ROE?

A. Yes. I recommend that the Commission:

1. Adopt CUB's recommended return on equity framework as discussed in Dr. Kihm and my testimonies.
2. Adopt a set of quantitative approaches to estimating the utility cost of equity consistent with finance principles, as discussed by Dr. Kihm.
3. Explicitly reject the flawed methodology used by Ms. Bulkley to estimate the utility cost of equity, as described in Dr. Kihm's testimony.

4. Authorized a test year 2023 return on equity for WEPCO and WG of 9.0 percent.
5. Specify a set of key performance areas and/or specific performance metrics it wishes to consider in future utility rate proceedings.

Other Revenue Requirement Issues

Q. Applicants propose to reflect the retirement of the South Oak Creek power plant Unit 5 in May of 2024. Do you have any comments regarding this proposal?

A. Yes. As discussed in Mr. O'Donnell's direct testimony, Applicants proposed to address this issue through a limited reopener proceeding for the 2024 test year. As no alternative has been proposed to-date, Applicants will be seeking continued recovery of undepreciated plant costs associated with Unit 5 using a "traditional" recovery method. This means that plant related costs for Unit 5 would be recovered from WEPCO's customers as if the plant were still operational. I have concerns regarding this approach.

Q. Please explain.

A. Once the Unit 5 is retired, it will no longer be used and useful for the purposes of providing electric utility service to WEPCO customers. One of the core principles of regulated utility ratemaking is that utility plant costs should not be recovered through rates unless that plant meets the "used and useful" standard. Examples of the application of that standard can be found in a number of instances where this Commission has either disallowed recovery or allowed for accounting deferrals in instances where it was known that new utility investments would not be service during a given test year, or where the timing of the in-service date was uncertain. To allow for full "traditional" recovery of the plant costs associated with facilities that are retired early would be inconsistent with general Commission ratemaking practices as well as regulatory theory.

Q. Are you suggesting that the Commission disallow the recovery of all undepreciated costs associated with unit 5?

A. No. While such a disallowance would provide significant rate relief to WEPCO's electric customers, to do so would be inconsistent with ratemaking policy. Specifically, the investments WEPCO has made to-date were deemed by the Commission to have been prudent at the time they were reviewed by the Commission, such as through the CPCN process. As such, to not allow WEPCO recovery of their investment would be inappropriate given the circumstances of these past Commission decisions. However, while continuing to allow the company recovery *of* its investments in the plant is likely reasonable, the same cannot be said for allowing the utility recovery *on* its investment.

Q. Do you have a recommendation regarding the recovery of these costs?

A. As discussed in Mr. O'Donnell's testimony, significant ratepayer benefit can be provided through alternative financing of some or all of the stranded asset costs associated with South Oak Creek, in particular securitization. Consistent with his testimony, I recommend that the Commission direct WEPCO to pursue securitization of undepreciated environmental control costs associated with South Oak Creek. Should the Commission determine that it lacks the necessary authority to require WEPCO to securitize stranded South Oak Creek costs, I recommend that the Commission consider other regulatory actions it may take in order to incentivize the company to pursue alternative financing measures that will lower costs for customers.

Q. Do you have example of an action the Commission could take?

A. Yes. Consistent with the previous discussion regarding utility ROE, the Commission could impose an ROE penalty if the company elects not to pursue securitization or other measures that provide comparable rate relief.

Q. Why would this be appropriate?

A. As discussed in Mr. O'Donnell's testimony, securitization provides a significant benefit to utility customers at the expense of shareholder earnings. As such, if the Commission lacks authority to force action on the part of WEPCO, and WEPCO declines to take meaningful steps to mitigate the cost recovery associated with stranded plant costs in order to protect its shareholders, the Commission could lower the company's authorized ROE in order to rebalance customer and shareholder interests.

Q. The applicants have proposed inclusion of amortized COVID-related costs in test year revenue requirements. Do you have any comments regarding this?

A. Yes. Based on my review of Applicants' testimony and exhibits, I am unable to determine the extent which these amortized costs, or test year uncollectables and bad debt expense, include bad debt associated with arrearages accumulated during the COVID disconnection moratorium. To the extent that these arrearage costs are contemplated for recovery during the test year, the Commission may wish to consider whether some adjustments to test year expense would be appropriate in order to provide rate relief to customers and implement a cost sharing between the customers and the utility shareholders.

Utility Rate Design

Q. Can you please describe the utility rate design process?

A. Yes. At the simplest level, the rate design process for regulated utilities is meant to produce a set of retail rates which allows the utility to recover its total retail revenue requirements that are determined to be just and reasonable by the Commission. Viewed through this lens, rate design is a "simple" math problem of deriving rates that, when applied to test year forecasted billing units, yields the revenue requirement set by the Commission. As such, the rate design process involves the use of quantitative tools, such as the embedded cost of service study, to allocate the utility's costs across its various customer classes and service types and design final rates.

As Mr. Nelson indicates the rate design process is commonly guided by the "criteria of a desirable rate structure" as set forth by James C. Bonbright in "Principles of Public Utility Rates:"[17]

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    a. in the control of the total amounts of service supplied by the company;
    b. in the control of the relative uses of alternatives types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi-party line)[18]

[17] Bonbright, James C., 1961, *Principles of Public Utility Rates*, New York and London: Columbia University Press (hereafter "Bonbright"), p. 290-291.
[18] Id.

A review of Bonbright's enumerated criteria clearly reveals a list in conflict with itself. For example, "fairness" in the apportionment of costs may conflict with strict economic "efficiency" of rate classes. "Public acceptability" also looms large as this subjective criterion can conflict with a variety of other more objective criteria. This indicates that utility rate design, more than being simply a quantitative exercise, involves judgment on the part of the rate analyst, but more importantly, on the part of the Commission. This is partly why one commonly hears rate analysts refer to rate design as an art, not a science.

Utility regulation, with rate design captured under its umbrella, is a form of economic regulation, the legal framework for which involves application of standards such as "just and reasonable" and "fair." As with my discussion of utility ROE, adherence to these legal standards ultimately requires making public policy decisions based on quantitative evidence. And as with ROE, a formula cannot provide the final answer on rate design for the Commission. Bonbright himself harshly criticizes those who would seek to restrict rate design to solely "economic" (i.e. quantitative) principles:

> The significance of such statements require notice in this chapter, since they raise the puzzling question of how *any* public utility rates or rate-making policy could have an affect on individual or social welfare other than an *economic effect*…
>
> the most frequently made use of this self-imposed restriction to "economic" principles is to absolve the economist from any professional concern for considerations of *fairness or equity* as between investors and consumers, or as among different classes of customers…[19]

Bonbright goes on to critique a contemporary economist writing on the subject of cost allocation who declares they will analyze a problem of cost allocation solely "from an

[19] Bonbright p. 31 (emphasis in original).

economic point of view. Whether or not the various methods proposed could give results that are 'just' or 'equitable' will not be discussed."[20] Bonbright states:

> They are omitted, presumably, because they raise ethical questions, as to which an economist has no professional competence.[21]

One need only consider that Bonbright's oft-cited work includes chapters on "Social Principles of Rate Making" and "Fairness versus Functional Efficiency as Objectives of Rate-Making Policy." While I do not agree with every conclusion reached by Bonbright regarding these topics, his inclusion of these discussions make clear that policy considerations beyond strict economic efficiency and slavish devotion to model results are critical to just and reasonable utility rate design

Many rate analysts seemingly jump past all of this, straight to a citation of Bonbright's ratemaking criteria, plunging directly from there to an exhaustive discussion of their cost allocation methodology and model results, concluding with the argument that a particular rate design is desirable because the model states it must be so.

Q. Are you suggesting that quantitative methods don't matter?

A. Absolutely not. Cost allocation modeling results, for example, are an invaluable tool in the development of utility rates. Indeed, what follows includes my own exhaustive discussion of cost allocation methodologies and model results. However, what I am suggesting is that if one is to, in good faith, invoke Bonbright as a guide to setting utility rates, one must accept that "Bonbright" consists of more than a list of criteria, but also an illustrative discussion of the importance of "fairness" and how public policy judgment must play a critical role in the Commission's determination of just and reasonable rates.

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[20] Bonbright p.32, direct quote from Ralph Kirby Davidson, 1955, *Price Discrimination in Selling Gas and Electricity*, Baltimore, MD, p. 111

[21] Bonbright p. 32.

Q. Do you have any other comments on the rate design process?

A. Yes. A complicating factor for the Commission is that the aforementioned application of public policy judgment is woven throughout the rate design process. With ROE, there are two fairly discreet steps, as Dr. Kihm and I have discussed: 1) The estimation of the utility cost of equity through the application of finance principles and quantitative methods; and then 2) The determination of an authorized ROE, which requires a public policy decision on the part of the Commission.

When considering utility rate design, however, public policy decisions are peppered throughout. It is not as simple as taking a model output and layering a policy decision on top to arrive at final rates. While the determination of final class revenue responsibility and authorized rates clearly involves the application of judgement, policy considerations are not confined to these final steps. As will be discussed below, many of the decision points a rate analyst must make, and the Commission must evaluate, regarding cost allocation involve questions of both economic efficiency and fairness, thus influencing the cost of service model results. This is precisely why Bonbright addresses issues of fairness, of whether cost allocation decisions are "just" or "equitable," in his discussion of utility rate design.

Embedded Cost of Service (COS)

Q. Please describe the function of the embedded COS study (COSS) in the regulatory ratemaking process.

A. The COSS is an analytical tool that allocates a company's revenue requirement, principally its expenses and capital investment costs, across the various customer classes. The COSS seeks to assign these costs to the utility's customer classes based on cost causation principles. The results of the COSS provide a quantitative tool to aid in assigning class revenue responsibility and designing utility rates in a manner that reflects the utility's cost to serve its customers. Mr. Stasik provides an overview of the process for developing a COSS in his direct testimony, so I will not repeat that here. (Direct-WEPCO/WG-Stasik-3 to 5)

Q. Is there one universally recognized methodology for a COSS?

A. No. The results of a COSS are driven by the methodological choices made at the various steps in the cost allocation process, particularly the cost classification step and the allocator development and selection steps. These methodological choices create the potential for a range of reasonable cost allocations, depending on one's view of utility cost causation. Differences of opinion regarding the fundamental principles of regulatory ratemaking can also influence the development of a COSS. My own view is that those principles are better reflected where greater weight is given to studies utilizing cost allocation approaches that most accurately mirror what we know to be true about the utility system being modeled. Doing so results in a class cost allocation that better reflects utility cost causation.

As noted by Mr. Stasik, the foundational principle of utility cost allocation is the concept of cost causation. This is sometimes articulated as the principle of cost-causer, cost-payor. As noted by Mr. Stasik, the concept of cost causation dictates that "the costs that customers become responsible to pay should be the costs that those customers caused the utility to incur because of the characteristics of those customers' usage of utility service" (Direct-WEPCO/WG-Stasik-3) I would also extend Mr. Stasik's summary and argue that costs should be assigned to the customers who cause the utility to incur those costs in a manner that reflects *the way in which the costs are incurred* by the utility. From this perspective, CUB and the Applicants agree regarding the fundamental principle of cost allocation. However, as I have previously noted, there are numerous approaches that can be employed when allocating utility costs. Disagreement regarding the appropriateness of one method versus another is the source of the common conflicts in the area of cost allocation, particularly retail class cost allocation.

Q. Have cost of service studies been performed in this proceeding?

A. Yes. As part of its application to adjust rates for the 2023 test year, WEPCO-WG provided the results of its preferred electric, natural gas, and steam COSS models, at the Applicants' requested revenue requirement levels. Additionally, at the request of Commission staff, WEPCO-WG provided the results of its COSS model adjusted to reflect five additional scenarios, as well as its preferred COSS, at staff's audited revenue requirement levels. This set of COSS runs requested by staff reflects a range of cost allocation approaches and overall methodologies that capture the preferences of parties such as CUB and the Wisconsin Industrial Energy Group (WIEG), as well as other methods that have historically been introduced in proceedings before this Commission. Commission staff also requested that the Applicants supplement their preferred natural gas COSS with the COSS B approach commonly presented in Commission rate proceedings. A summary of the adjustments applied to produce the electric COSS scenarios are presented in Mr. Stasik's supplemental direct testimony at Direct-WEPCO/WG-Stasik-s-2. A summary of the electric and natural gas COSS results can be found in Response-Data Request-PSC-TCM-2.01 and Response-Data Request-PSC-TCM-2.01, respectively. My expectation is that both of these data request responses will be included in a delayed staff exhibit, consistent with recent practice before the Commission.

Electric COS

Q. Considering the range of COSS results requested by Commission staff and presented by Mr. Stasik, is there a particular COSS you believe is most appropriate for the purposes of determining the Applicant's test year class revenue responsibility and rate design?

A. Yes. For the reasons discussed below, I believe that Scenario 6 is the most appropriate.

Q. You previously noted common points of conflict regarding COSS methodologies. What electric utility costs are typically the subject disagreement when discussing cost allocation?

A. First, I would note that a utility COSS is the product of hundreds of individual methodological choices primarily related to cost classification and allocation. Studies that bear surface resemblances may have a number of small differences that affect study results. However, in general terms the following are the most commonly-contested electric utility cost allocation issues in proceedings before this commission:

- Production Plant
    - Classification of production plant – Demand vs. Energy
    - Treatment of non-firm demand
    - Basis for the allocation of demand-related costs – e.g. 12CP vs 4CP
- Distribution Plant
    - Classification of distribution plant – Demand vs. Customer
- Administrative and General Expense
    - Classification of expense – Customer vs. Commodity

While there are a number of small differences between the five electric COSS prepared in this proceeding, the differences in the results produced by the range of COSS models are largely a result of differing approaches to the above cost allocation issues.

Q. Can you please discuss the allocation of electric production plant?

A. Yes. As I just noted there are three general issues related to the allocation of electric production plant. First, in the classification of production plant costs, some parties disagree whether production plant should be classified as either a 100 percent demand-related cost, or if production plant should be classified as partly demand-related, and part energy-related.

Q. Do you believe one of these production plant classification approaches is more appropriate?

A. Yes. I believe that it is appropriate to classify production plant as both demand- and energy-related costs. As described in the Electric Utility Cost Allocation Manual produced by the National Association of Regulatory Utility Commissioners (NARUC Manual):

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.[22]

Using a demand/energy classification for production plant recognizes the diversity in a utility's generation fleet. The various generation sources within a utility's portfolio play different roles in meeting the utility's electricity supply needs, in terms of meeting peak demands for reliability purposes while also providing low-cost energy to the utility's customers. A demand/energy classification recognizes that the utility does not solely consider peak demand

[22] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, Washington DC: NARUC, 1992, p. 49 (hereafter cited as "NARUC Manual").

needs when investing in generation plant. Considered another way, if utility investment in generation facilities were solely a function of demand, then peaking plants such as combustion turbines (or increasingly, solar photovoltaic), which have a lower installed per megawatt (MW) of capacity, could be built in place of large base load units that have a higher per MW cost. Indeed if taken to its logical conclusion, if demand were the sole cost causation factor for electric production plant as a 100 percent demand classification implicitly asserts, utility investment in peaking resources would be the only production plant investment that could be deemed reasonable and prudent – virtually any other type of generation facility would violate least-cost principles when compared to the per-MW cost of peaking unit. However, the reality is that achieving a low average cost of energy is also a factor in determining what type of units are installed. For example, base load and intermediate plants like combined cycle facilities are built because they have lower average energy costs than peaking units. Using a combined demand/energy classification reflects the trade-off between production cost and capital cost made by WEPCO when it decides what plants should be built. A demand/energy classification reflects the way in which these costs are incurred by the utility.

Finally, as is discussed in more detail below, MISO is currently in the process of evaluating and modifying its resource adequacy construct in order to meet future needs. Beyond simply considering peak demand requirements, MISO has also indicated that explicit consideration of the deliverability of energy, not just meeting demand during peak hours, will become increasingly important as the region's generation continues to integrate more intermittent resources such as solar PV. To that end, MISO has begun stakeholder discussions of critical generation resource "attributes" that go beyond simple capacity as it seeks to meet future market and regional reliability needs. This further emphasizes that energy and demand are two sides of the same coin, and that allocation of production plant must consider both if one is to accurately reflect the planning decisions that drive utility investment in production resources.

Q. Is it your testimony that the Commission should reject classification of production plant as being 100 percent demand-related?

A. Were the adoption of a single COSS an issue in this case, yes, it would be for the reasons already discussed. Certainly, the Commission could elect to make that determination based on its review of the record. However, I do acknowledge that absent such a decision this Commission has the long-standing practice of considering the results of multiple COSS in determining final revenue allocation and rate design.

Q. What production plant classification methods are used in the six electric COSS?

A. A table summarizing the production plant classification methods used across the various COSS prepared in this proceeding can be found below.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Classification	Demand	Demand	Demand/ Energy	Demand/ Energy	Demand/ Energy	Demand/ Energy
D/E Ratio	NA	NA	75/25	75/25	60/40	40/60

Q. Is there a demand/energy classification that you believe is reasonable to use for WEPCO's 2023 test year?

A. Yes. Based on the test year average 12-month coincident peak demand and energy requirements used in the company's originally filed COSS, and using an "average-excess" approach, I believe that a production plant classification of approximately 60 percent energy-related is reasonable. The remainder of production plant would be classified as demand-related.

Q. You previously noted that the treatment of non-firm demand is also a commonly contested electric cost allocation issue. Can you please describe the approaches used to address non-firm demand when allocating electric production plant?

A. In proceedings before this commission, parties have historically advocated for one of two approaches:

- Remove non-firm demand from the test year coincident peak (CP) demand allocators,[23] and allocate demand-related production plant on the basis of firm CP demand only, or
- Make no adjustment to the CP allocation factors, allocating demand-related production plant on the basis of total coincident peak demand. Separately, apply a credit to the retail classes equal to the non-firm CP demand times an estimated value of capacity. The cost of this credit is then allocated to classes based on total CP demand.

Q. Do you believe that one of these two approaches is more appropriate for the Commission to consider when assigning class revenue responsibility?

A. Yes. I believe the second approach, which I will refer to as the "Interruptible Credit" method, is more appropriate. This method is reflected in the results of COSS Scenario 6.

Q. Please explain why that is.

A. First, it might be helpful to take a step back and consider some of the fundamentals of utility regulation and ratemaking.

In issuing a final decision, such as in a rate proceeding, the Commission is required by Wisconsin statute to make findings of fact and conclusions of law. The generally

[23] Refers to an allocation factor that assigns cost on the basis of each class's contribution to the utility's peak demand.

understood implications of this are that the Commission's conclusions are to be fact-specific to the proceeding and the record produced in that proceeding. As a practical matter, it is thus desirable that the evidence within a utility proceeding be as fact-specific to the utility/utilities and issues before the Commission, so as to ensure optimal outcomes from the perspective of the public interest.

The role of the COSS within that process, as previously noted, is to serve as a quantitative tool to help guide the assignment of class revenue responsibility and the development of utility rates. I believe it is important to emphasize this point – that cost allocation is not an exercise unto itself whose use and usefulness ends once class revenue allocations are decided. Cost allocation and the COSS model are tools to help translate the utility's overall revenue requirement into authorized rates. Those rates serve a dual function. First, they provide sufficient revenue to allow for the recovery of expenses and capital investments, along with an opportunity to earn a reasonable return, for costs that the Commission *has already* approved recovery of. Second, rates provide an economic price signal to customers to encourage efficient, and in turn lower overall average cost, use of the utility system *in the future*.

Within the context of non-firm electric service, then, the goal of the cost allocation and rate design process should be the development of non-firm rates that encourage customers to supply the utility with an interruptible capacity resource that allows the utility to avoid making an investment in the *next* unit of generation capacity. By employing the Interruptible Credit method one is able to identify the value of that future avoided capacity separately from the allocation of existing production plant in a way that is more fact-specific to the goal of developing rates that encourage customers to provide interruptible capacity in the future.

If one instead simply removes non-firm demand from the CP allocators, a net-of-interruptible approach, you have effectively set the value of avoided capacity equal to the demand-related costs that the utility incurred in the *past,* not the *forward looking* or marginal value of avoided capacity. Using this approach instead of the Interruptible Credit method applies a blunt instrument where a tool with greater precision and accuracy could be used instead.

Q. Are there other reasons you believe the Interruptible Credit method is more appropriate than the net-of-interruptible approach?

A. Yes, one is related to something I just noted. The net-of-interruptible method implicitly sets the value of non-firm capacity equal to past embedded production capacity costs, rather than the forward-looking marginal cost of capacity – an approach that is unlikely to be accurate. But more than that, depending on what other cost allocation methodology choices have been made, it also runs a significant risk setting the value of non-firm capacity too high. Consider for example, the overall production plant cost allocation approach preferred by WEPCO: a 100 percent demand classification of production plant coupled with a net-of-interruptible treatment of non-firm demand. Using this approach, a non-firm customer would be allocated, and thus be pay for, $0 of production plant costs. The only production costs these customers would bear would be fuel and O&M expense. This despite the fact that many customers who take non-firm service are high energy usage, often high load-factor customers. These customers are subject to the possibility of capacity curtailments and system energy economy constraints, which as discussed before is the source of the economic benefit provided by these customers to the utility system. However, these curtailments or constraints are typically limited to a certain number of hours per year. For example, in the case of WEPCO's CP-3 General Primary Curtailable Service, the currently authorized tariff specifies:

> The sum of capacity curtailments and system energy economy constraints will not exceed 300 hours of curtailment in any calendar year. The Company will limit the duration of any one curtailment to eight hours between the hours of 8:00 a.m. and 10:00 p.m. prevailing time.

Given these limitations, I believe that it is unreasonable to classify production plant costs ass 100 percent demand-related and to also then allocate those costs to the utility's classes on a firm demand, or net-of-interruptibles, basis. The use of such an approach allows non-firm customers to have their cake and eat it too: they benefit from the utility's relatively low embedded cost rate during at least 96.5 percent of the time (8460 hours) without contributing to the capital costs for the company's generating facilities that enable that low cost of energy. These costs are then pushed to firm load customers. I do not believe that produces a fair result. The only way such a cost allocation methodology would make sense would be if, rather than of using the company's generation facilities to serve non-firm load during all non-curtailed hours, the company simply delivered a pile of coal or left a natural gas fuel truck on the customer's doorstep. For these reasons I believe that a cost allocation approach that takes the extra step of explicitly valuing the cost of interruptible capacity is more reasonable.

Q. Could you please summarize the non-firm demand treatments used across the six COSS models?

A. A summary table is provided below:

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6

Allocation Factor	Net-of-Interruptible	Net-of-Interruptible	Net-of-Interruptible	Net-of-Interruptible	Net-of-Interruptible	Interruptible Credit

Q. Can you please discuss the issues surrounding the selection of a CP demand allocation factor for the allocation of production demand-related costs?

A. In the allocation step of the COSS, once one has classified certain production plant costs, the next step is to determine what demands drive cost causation for utility production plant. Generally, the positions proffered in proceedings before this Commission advocate for either the use of an allocation factor that considers the CP demand of all 12 months in the test year or an allocation factor that only considers a subset of months, most commonly the four months with the highest total CP demand. These two allocation factors are commonly referred to as 12CP and 4CP, respectively.

Q. Is there a production demand allocation factor that you believe is more appropriate between these two?

A. Yes. I believe that 12CP is the more appropriate allocation factor to use when allocating demand-related production plant.

Q. Why is that?

A. Use of 12CP recognizes that the utility must be able to meet peak capacity needs in all 12 months of the year, even if those peaks are lower in absolute terms than in the months with the highest CP demand.

Fundamentally, when compared to 12CP, the issue with the 4CP method is that it requires that one accept the premise that WEPCO's production capacity costs are incurred only to serve peak loads during the four highest month of the year, and that capacity needs and reliability in non-peak months are irrelevant. WEPCO has built generation and purchased capacity in order to meet reliability standards. Similarly, WEPCO 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, MISO would allow WEPCO 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 WEPCO's generating plants provide reliability during the entire year, not just during the four summer months.

The value of capacity resources is also not limited to those months with the highest absolute CP demands. It is true that peak demand months, most often the summer months of June through September, contribute significantly to the utility's investments in generation capacity. This makes common sense: the hours, days, and months with the highest absolute demands require investment in equally large quantities of generation capacity to avoid resource scarcity during those periods, again in absolute terms. However, an erroneous extension of this common-sense notion leads many to conclude that capacity scarcity, or tightness, is only associated with periods of high demand. In fact, capacity tightness also occurs during non-peak months, in part owing to the fact that in absolute terms those months see lower peak demands. It is during these lower-demand periods that utilities will typically schedule unit downtime and maintenance, thus removing resources from the grid and rendering them unavailable to meet unexpected periods of resource scarcity.

For example, MISO issued a Capacity Advisory for Monday, October 8, 2018 due to its forward-looking capacity assessment having indicated a potential limited generation surplus condition.[24] While MISO forecasted sufficient resources to meet load serving requirements for that day, if there had been any losses in generation availability or energy imports, MISO would have triggered its Market Capacity Emergency procedure. This was an event that occurred outside the "traditional" peak summer months. Similarly, on January 17-18 of 2018, again a non-peak month, the MISO South region experienced a Maximum Generation Event due to extreme cold temperatures and atypical load. This event required MISO to make emergency energy purchases to meet South Region load obligations, manage the regional dispatch transfer, and maintain reliability. While this event was focused on the MISO South region, MISO also declared a Modified Maximum Generation Alert on January 17 for the North and Central regions, the latter of which includes Wisconsin. This again illustrates that a need for adequate generation capacity exists beyond the four months where WEPCO experiences the highest CP demands, moreover it highlights that the vast and interconnected nature of the MISO system requires that WEPCO not only have sufficient capacity to meet its own resource adequacy requirement, but that WEPCO's generators may be called upon in non-peak months in order to ensure system reliability. As a final example, the "polar vortex" events of 2014 caused MISO to declare footprint-wide Maximum Generation Alerts and Warnings in January and March of that year. Again, in non-peak months.

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

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[24] https://[www.misoenergy.org]/markets-and-operations/notifications-overview/real-time-operations-notifications/capacity-advisory-message/ (Accessed 8/23/2019).

against the risk of purchasing energy at a high cost. The 4CP approach assumes that this cost-hedge has no value during the non-summer months.

Q. Are there any other factors that you have considered as it relates to the selection of a production demand allocation factor?

A. Yes. Recently, MISO and MISO stakeholders have been discussing the future of capacity accreditation within the MISO region. While I do not believe the intricate details of this process are relevant to this proceeding, what is relevant is that this process has resulted in MISO adopting an "all hours matter" approach to developing its future market constructs. Consistent with this, MISO has applied for approval from the Federal Energy Regulatory Commission for approval of a seasonal capacity construct for thermal generation, representing a shift away from current practice which only considers a narrow number of hours during summer peak months. MISO and its stakeholders are engaged in a process to consider revisions to its non-thermal capacity accreditation that would similarly include a year-round and seasonal aspect.

In light of all of the foregoing considerations I find it difficult to accept that the use of a 4-CP demand allocator continues to have any value for the purposes of allocating production plant.

Q. Is it your testimony that the Commission should reject classification of production plant using a 4-CP allocation factor?

A. Again, were the adoption of a single COSS an issue in this case, yes, it would be for the reasons already discussed. However, I again acknowledge that absent such a decision this Commission has the long-standing practice of considering the results of multiple COSS, barring an explicit determination that certain methods are in invalid going forward.

Q. Which COSS use a 12CP production demand allocation factor and which use 4CP?

A. A summary table is provided below:

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Allocation Factor	4-CP	12-CP	4-CP	12-CP	12-CP	12-CP

Q. You previously noted the classification of distribution system costs as a commonly contested cost allocation issue. Can you please provide an explanation of this issue?

A. Disagreements regarding distribution cost allocation methods most commonly center around the question of how components of the distribution system are classified, either as demand- *or* customer-related costs or a combination of demand- *and* customer-related costs. Specifically, analysts disagree as to whether or not the costs booked to FERC/PSCW USOA (Uniform System of Accounts) accounts 364-368 should be classified as demand-related costs only, or whether a portion of these costs should be classified as customer-related. These accounts correspond to the following components of the electric distribution system:

- 364 – Poles and Towers
- 365 – Overhead Conductors
- 366 – Underground Conduit
- 367 – Underground Conductors
- 368 – Line transformers

In instances where these costs are classified as partially customer-related, an analyst will typically employ some form of minimum system analysis in order to classify the customer related portion of these distribution plant assets. A minimum system analysis will generally take the form of a minimum size study, where 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, and the costs in excess of the minimum size are classified as demand-related costs. Where the utility possesses sufficient data about its distribution plant assets, a zero-intercept study may be used, applying a linear regression to estimate the proportion of distribution plant costs that are "identified" as customer-related. Depending on a utility's particular circumstances and the preferences of the analyst preparing the COSS, these two minimum system methods may be mixed and matched. The theoretical goal of either of these two approaches is to estimate the costs of the "minimum system." Put another way, a minimum system analysis seeks to answer the question: "what would be the costs associated with a distribution grid that looks like the one the utility has constructed but has zero load carrying capacity?" Those costs are then assumed to be customer-related costs. Typically, costs booked under Accounts 369 and 370, services and meters respectively, are classified as 100 percent customer-related. This effectively directly assigns these costs to customers.

Opposite the Minimum System method is the Basic Customer method. As will be discussed below, under the Basic Customer method, the distribution system assets in accounts 364-368 are classified as demand-only costs. Like in the case of the Minimum System method, services and meter costs are classified as customer-related. A summary of the distribution system cost classification method used in the six COSS scenarios presented in this proceeding.

	Scenarios 1-5	Scenario 6
Method	Minimum System	Basic Customer

Q. Between the Minimum System and Basic Customer method, which do you believe is more appropriate for the Commission to consider when assigning class revenue responsibility?

A. I believe the Basic Customer method is a more appropriate basis for the classification and allocation of Distribution system costs.

Q. Why is that?

A. Fundamentally, my concern with a Minimum System approach is that it overstates the allocation of customer-related costs. For example, when the minimum size method is used, the minimum sized distribution system components (e.g. the smallest overhead or underground conductors) that are meant to represent the cost of a zero-load carrying capacity system still have a load-carrying capacity. As a result, part of what is allocated as customer-related under the minimum system method would more accurately be classified as demand-related. Employing a zero-intercept approach to estimating a utility's "minimum system" would appear to solve this problem as you have quantitatively "solved" for zero. However, as with any minimum system approach, it does not adequately reflect customer density and location, such as in urban environments or dense residential areas. This limitation of the minimum-system approach is described in Bonbright:

> But the really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be *definitely* earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity…. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers."[25] (emphasis added)

> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customer per linear mile or per square mile). Indeed if the company's

[25] Bonbright, *supra*, pp. 347-48 (hereafter cited as "Bonbright")

entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[26]

Ultimately the shortcoming of a minimum system approach is the fact that it seeks to classify distribution system costs such as overhead and underground conductors, poles, conduit, and line transformers as customer-related at all. A consequence of classifying these costs as customer-related is that they are considered to be part of the marginal cost of a customer being added to the system. In simpler terms, classification of distribution system cost as customer-related requires one to argue that when a customer is added to the utility's grid, the customer causes the utility to incur some additional cost on a one-for-one basis on every distribution system component, from the customer's meter to the point where the grid connects to the transmission substation. While this argument is simple to accept for meters and the customer's service drop – facilities that are most proximal to the point of the customer's interconnection – a customer (particularly a small customer) does not typically cause the utility to incur additional costs for the lines, poles, and conduit simply by being a customer, regardless of how much electricity they use or whether they use any at all. Further, a minimum system approach asks a customer to bear a portion of the primary (high) voltage distribution system as a customer varying cost. As the "poles and wires" portion of the distribution grid that is electrically farthest removed from the service point of most customers, it is unlikely that the addition of individual customers influences the utility's primary voltage system planning, beyond consideration of those customers' contributions to peak demand.

[26] *Id.*

Beyond these critiques, classifying "poles and wires" costs as customer costs and then recovering those costs through fixed customer charges completely ignores the fact that distribution system assets, such as poles and wires and transformers, are sized based on load-carrying capacity. Even line transformers, which are often one of the first pieces of the distribution system upstream of the customer's service drop, are sized based on capacity. The utility does not purchase a "one customer" transformer, or a "three customer transformer." No, it purchases transformers with a specific capacity rating and sites them as appropriate to serve downstream loads. As such these costs are most appropriately classified as being related to consumption in some way, either demand, energy, or both.

Returning to a previous discussion, one must also ask: is it fair to assert that customers bear a *per-customer* responsibility for causing the utility to incur the costs associated with the distribution lines that run over our heads or under main street? I don't believe so.

I acknowledge that it is natural, if one has a narrow accounting-centric view of the world, to see such utility costs as fixed. Certainly, when one looks at utility plant balances from one year to the next, the differences can be small. However, the reality is that most utility system costs do not represent some kind of immutable monolith. Rather, they can and do vary over time, with most investments driven by the need to meet the customer's consumption, not the number of customers on the system.

Lastly, I find it odd that so many take this approach of doggedly insisting there is some "customer related" component when allocating distribution system costs. Production plant represents a type of investment similar to distribution plant where a set of large, long-lived, and often lumpy investments serves a similarly large number of customers. And yet, despite production plant costs not varying much from year to year, we do not pretend that there is some customer-related component to those costs that should be allocated on a customer basis and recovered through fixed customer charges. No, we appropriately classify those costs as being driven by customer usage and allocate them accordingly.

Q. Why is this important?

A. If we set rates so that costs that are ultimately variable in the long-term are priced on a fixed basis, we break the long-term cost-causation relationship and set the cost of a unit of electricity consumption too low. Consequently, basic economic theory would suggest that this would lead to economically inefficient over-consumption, and the incurrence of some future costs that could otherwise have been avoided if the rates had been set appropriately. We recognize this basic fact of cost-causation for production-side utility costs. We classify, allocate, and price production (and transmission) resources based on demand and energy based on the recognition that, in the aggregate, incremental decreases in customer consumption in response to volumetric charges can bend the cost curve for those resources over the long term, thus lowering utility costs. The same cost causality exists with distribution system costs. As such, similar cost allocation methods should be used.

Beyond economic efficiency, equity is also negatively affected by the use of a minimum system cost-allocation approach and the resultant over-classification of costs as "customer varying." Some argue that increasing fixed charges sends a more "accurate" price signal to the customer regarding the utility's cost to serve them. Notwithstanding the previous discussion as to why this is an incorrect view, it is simply unfair to the customer to roll increasingly large portions of the utility's revenue requirement into correspondingly larger fixed charges and call it a "price signal." Public utility electric, natural gas, water, sewer, and increasingly telecom, services are essential services, not luxuries. What function, other than to be punitive, does sending a fixed "price signal" serve if the customer has no way of responding to it? Moreover, setting fixed charges too high based on inappropriate cost allocation methods creates inequities within customer classes where low-use customers subsidize the service of customers with above-average usage patterns.

Q. How does the basic customer approach handle the allocation of these costs?

A. The basic customer cost approach classifies as "customer related" or "customer varying" only those costs that vary directly with a customer taking service from the utility. Specifically, one would only classify the following costs as "customer" costs:

- Meters
- Services
- Meter reading billing and other customer account expenses

This "basic customer cost" method or approach better aligns with cost causation. Unlike the minimum system approach, which would ultimately see large portions of the distribution system recovered through fixed "customer" charges, the basic customer method recognizes that in the long term most of the distribution system and its associated costs are variable and vary with customer demand or usage. By classifying all but the above short list of costs as being tied to consumption, either demand or energy, the basic customer method allows one to appropriately recover these long-run variable utility costs via variable charges.

Q. Are there any other differences between the minimum system approach and the Basic Customer Cost Method?

A. Yes. Under the basic customer cost approach, sales expense and most administrative and general (A&G) expense are allocated on a commodity (energy) basis rather than being allocated on a customer basis, or based on the allocation of other utility accounts that are in turn allocated in whole or in part on a customer basis.

Q. Why is this done?

A. When one considers, for example, the costs booked under the various sales A&G accounts, one would be hard pressed to confidently draw a cost-causation "line" between those costs and the act of a customer taking service from the utility. In fact, by the definitions set forth within the Commission's uniform system of accounts for municipal utilities, sales and A&G expenses are not tied to the delivery of utility service.

Q. How should those costs be allocated and recovered?

A. I believe that sales and A&G utility expenses should be allocated and recovered in the same way analogous costs are recovered in competitive market industries. That is, that they should be recovered on a volumetric basis. To illustrate this, consider the following example.

I do not live in Pennsylvania. As such I do not patronize the convenience store chain Sheetz. However, if I were to take a road trip through the Keystone State and stop at a Sheetz for gas and food, they would not require that I, prior to making any purchases, pay a fixed charge to cover their land lease, janitorial, marketing materials, and employee benefits costs, simply for the privilege of being a customer. Instead, the convenience store recovers these costs on a volumetric basis through the cost of a gallon of gasoline, or a box of cheesy bacon tater bombs.

One of the tenets of utility regulation is that regulation, and by extension the Commission, serves as a proxy for a competitive market. As such it is most appropriate for sales and A&G costs, which are unrelated to the delivery of utility service, to be recovered on a volumetric basis as it is done in most other industries.

Q. Are there A&G expenses that have been allocated on a customer basis in COSS Scenario 6, the scenario that utilizes the basic customer method?

A. Yes. Account 904, uncollectable expense, is allocated according to the company's forecasted test year uncollectable "budget" per customer class. My understanding of the use of this approach is that it is meant to directly assign uncollectable costs to the classes where those uncollectable and bad debt expenses are accrued. This is how most if not all Wisconsin IOUs treat these costs for cost allocation purposes.

Q. Do you believe this allocation treatment is appropriate?

A. I can see the merits in this approach from a strict cost-causer cost-payor perspective. However, I believe that the appropriateness of this approach is ultimately a policy decision. Nearly any alternative to this approach would involve socializing these costs across all customer classes to some extent. As it stands currently uncollectable costs are directly assigned to the classes and as such are then folded back into rates. If one views the source of much of the utility's uncollectable expense to be inability to pay due to economic hardship or similar factors, the Commission may wish to consider whether it is appropriate to roll uncollectible costs back directly onto the classes, thereby increasing rates, which in turn exacerbates affordability and energy insecurity. I believe that a strong policy argument exists that this type of vicious cycle is unreasonable and that broader socialization of these costs is appropriate.

Q. What effect would this have on the utility's rates?

A. It would likely decrease slightly the revenue requirements of the smaller customer rate classes, particularly the residential classes. Another consequence, would be that these costs would no longer be allocated on a customer basis, instead being socialized on the basis of another factor such as revenue. The result of this would be an incremental decrease in the customer related costs which would support a lower rate for the utility's monthly fixed customer charges.

Q. The summary table of distribution plant cost allocation methodologies shows that the Basic Customer approach is included only as part of COSS Scenario 6. Is this cost classification approach a methodological outlier?

A. No, as this would be a ridiculous claim. Decisions regarding the appropriateness of any one cost allocation method, including the basic customer method should be made based on the merits of the methods themselves, the assumptions their use implicitly represents, and the consequences of their use in the ratemaking process. To assert that the basic customer method is somehow "invalid" because it appears only once in this particular set of COSS scenarios would be just as ridiculous as claiming that the use of a 4-CP allocator is invalid because it only shows up two times out of six. The Commission is not holding a popularity contest.

This accusation of "outlier" has been levied in prior rate proceedings before this Commission – that because CUB is often the only party advocating the use of the Basic Customer method (or any other particular cost allocation method) in Wisconsin that it necessarily must be somehow improper. This is not true.

A similarly common argument against the basic customer method is to claim that the overhead and underground distribution system *must* be classified as demand- and customer-related costs because that approach is found in the NARUC Manual. The NARUC Manual was intended to be a survey of cost allocation methods that "should be simple enough to be used as a *primer* on the subject for new employees yet offer enough substance for experienced witnesses." (emphasis added)[27] The NARUC Manual is not authoritative as to which method is proper to analyze utility systems. This was specifically acknowledged in its preface, which states "The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons."[28]

Furthermore, the NARUC Manual has not been revised in 25 years. Ratemaking is not static and relying heavily on the NARUC Manual, rather than treating it as one source of guidance, not only misses the point of the NARUC Manual but becomes less reasonable with the passage of time.

The NARUC Manual is but a tool, a guide to help Commissioners and analysts develop a working understanding of utility cost allocation and utility ratemaking. In reading the NARUC Manual, as well as other seminal industry writings upon which it is based[29], I believe it is clear that the authors did not intend the Manual to be considered the sole, definitive reference, but rather that it serve as a starting point and source of information in connection with utility cost allocation. In fact, early in the NARUC Manual, the authors themselves recognize that "opinions vary on the appropriate methodologies to be used to perform cost studies . . ."[30]

However, if one were to begin with the NARUC Manual, one would find that it includes an example of a cost functionalization/classification scheme that includes an energy

[27] NARUC Manual, p. ii .
[28] *Id.*
[29] *E.g.*, Bonbright.
[30] NARUC Manual, p. 12

classification among the possible options for allocating utility distribution costs (*Id.,* p.34, reproduced below, emphasis added):

Cost Classes					
Functions		Demand	Energy	Customer	Revenue
Production	Thermal	X	X	N/A	N/A
	Hydro	X	X	N/A	N/A
	Other	X	X	N/A	N/A
Transmission		X	X	X	N/A
Distribution	**OH/UG Lines**	**X**	**X**	**X**	**N/A**
	Substations	**X**	**X**	**X**	**N/A**
	Services	N/A	N/A	X	N/A
	Meters	N/A	N/A	X	N/A
Customer		N/A	N/A	X	X

While I am not suggesting that distribution system costs be classified and allocated as energy-related costs in this proceeding, I believe this does begin to illustrate how even the NARUC Manual authors understood that the range of reasonable cost allocation methods is not bound to those for which detailed examples are provided in the Manual.

Q. Is it your testimony that the Commission should reject the minimum system method?

A. Again, were the adoption of a single COSS an issue in this case, yes, it would be. In such a scenario, I believe that the Basic Customer Method as employed in CUB's preferred COSS would be a more appropriate basis for distribution cost allocation.

Electric Revenue Allocation

Q. Have you reviewed Applicants' proposed electric class revenue allocation?

A. Yes.

Q. Do you have any comments regarding the proposed revenue allocation?

A. Yes. Based on my review of the range of COSS results, I support the Company's proposed electric class revenue allocation.

Q. Please explain why that is the case.

A. The Applicants' proposed electric revenue allocation closely resembles the results of COSS scenario 6. Additionally, as briefly discussed in Mr. Nelson's testimony, the Applicants' proposal explicitly reflects a moderation of the company's overall rate increase, particularly with respect to the residential customer class. Give the current economic climate I believe that the company's proposal is reasonable.

Electric Rate Design

Q. Have you reviewed the Applicant's proposed electric rate design?

A. Yes. With respect to the residential and small commercial classes, Applicants have not proposed any changes to its retail rate structure. Specifically, the company proposes to keep WEPCO's residential and general secondary customer charges at currently authorized levels.

Q. What rates are currently authorized for WEPCO's customer charges?

A. Currently authorized rates are equivalent to $16/month average monthly customer charge for residential customers, and General Secondary Service customers.

Q. Do you have an alternative recommendation for these charges?

A. Yes. A review of the COSS results in this proceeding reveals the following functionalized customer cost for the residential and secondary voltage flat rate customer classes.

	($/customer/day)			($/customer/month)	
Scenario	Res. Flat	Sec. Flat		Res. Flat	Sec. Flat
1-5	0.7626	0.9067		23.20	27.58
6	0.4135	0.4887		12.58	14.86

As I previously noted, the Commission has a long-standing practice of considering the results of multiple cost of service studies when setting retail rates. Viewed through that lens, the currently authorized charge of $16 is not unreasonable as it falls within the range of

COSS results. However, the functionalized per-customer classified costs estimated in a COSS is entirely driven by cost allocation decisions related to distribution costs and A&G expense. As discussed above, I do not believe that the methods underlying the results of scenarios 1-5 are reasonable with respect to the allocation of these costs. As such I recommend that the Commission lower WEPCO's authorized customer charge to equal $15/month. This would still fall within the range of COSS results in this proceeding and would also bring WEPCO's electric rates in line with the monthly customer charges authorized for Madison Gas and Electric Company, Northern States Power Company-Wisconsin, and Wisconsin Power and Light Company.

Natural Gas COS

Q. Do you have any comments at this time regarding natural gas COS and rate design?

A. Historically, CUB has preferred the cost allocation approached reflected in the natural gas COSS often referred to as "COSS B." COSS B is a commodity-oriented study. Commodity-oriented studies consider costs associated with mains as commodity/demand related costs. Consequently, such costs would not be allocated to service rate classes on the basis of the number of customers served, as is done under the Applicants' COSS. Commodity-oriented studies also treat common costs (i.e., general plant and administrative and general expenses) in a similar manner. More specifically, under COSS B, distribution main costs are classified only as either commodity- or demand-related using an average and excess approach. Under COSS B, general and common costs are allocated based on the assignment of directly allocated distribution plant. As such, the allocation of general and common costs under COSS B reflects a demand and commodity only classification of distribution mains. Finally, under COSS B, A&G expenses are classified as commodity-related costs.

COSS B shares a cost causation foundation with many elements of electric COSS Scenario 6 discussed above. As such, the arguments in favor of the COSS B approach mirror the theoretical arguments already discussed, and in the interest of brevity I will not repeat them here.

Natural Gas Revenue Allocation

Q. Have you reviewed Applicants' proposed natural gas class revenue allocations?

A. Yes.

Q. Do you have any comments regarding the proposed revenue allocations?

A. Yes. The class revenue allocation and rate designs for WEPCO and WG prepared by Mr. Korducki closely reflect the results of the company's preferred COSS, COSS A.

Q. Do you have an alternative recommendation for the Commission?

A. As previously noted, the Commission has a long-standing practice of considering the results of multiple COSS when assigning class revenue responsibility. As compared to electric, this process is greatly simplified for natural gas as there are only two embedded COSS presented for each gas utility. In the abstract, I would prefer that WEPCO and WG's final natural gas revenue allocation closely resemble the results of COSS B, for the reasons discussed above, I believe that COSS reflects a more reasonable approach to natural gas cost allocation. However, in light of the Commission's past practices, I recommend that the Commission allocate WEPCO and WG's final natural gas revenue requirement so as to better reflect the range of COSS results. Specifically, I believe that a class cost allocation that is closer to the midpoint between COSS A and COSS B, rather than biased towards Applicants' preferred approach, is more reasonable.

Natural Gas Rate Design

Q. Have you reviewed the Applicant's proposed natural gas rate design?

A. Yes. With respect to the residential and small commercial classes, Applicants have not proposed any changes to their retail rate structure. Specifically, the company proposes to keep WEPCO and WG's residential and small commercial charges at currently authorized levels.

Q. What rates are currently authorized for WEPCO and WG's natural gas customer charges?

A. Currently authorized rates for WEPCO are equivalent to $14.90/month average monthly customer charge for residential customers, and small commercial customers. For WG, Currently authorized rates for are equivalent to $10.04/month average monthly customer charge for residential customers, and small commercial customers.

Q. Do you have an alternative recommendation for these charges?

A. No. Based on my review of the functionalized customer costs estimated under COSS A and COSS B, I have no objection to the currently authorized charges for WEPCO and WG.

Q. Does that conclude your direct testimony?

A. Yes.