BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District	)	
Electric Company's Request for Authority	)	
to File Tariffs Increasing Rates for Electric	)	Case No. ER-2019-0374
Service Provided to Customers in its	)	
Missouri Service Area	)	

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

OF

THE MIDWEST ENERGY CONSUMERS GROUP

David L. Woodsmall
Woodsmall Law Office
308 E. High Street, Suite 204
Jefferson City, MO 65101
Phone: 573-797-0005
david.woodsmall@woodsmalllaw.com

ATTORNEY FOR THE MIDWEST
ENERGY CONSUMERS GROUP

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TABLE OF CONTENTS

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	)))	Case No. ER-2012-0174

PROPOSED FINDINGS OF FACT AND
CONCLUSIONS OF LAW

COMES NOW Midwest Energy Consumers' Group ("MECG"), by and through the undersigned counsel, pursuant to the Commission's April 28, 2020 *Order Further Modifying the Procedural Schedule*, and submits its Proposed Findings of Fact and Conclusions of Law on the issues set forth below.

I. BURDEN OF PROOF

1. Section 393.150(2) provides that, in any rate increase proceeding, the burden of proof is on the party seeking the increased rate.

2. The Supreme Court has provided a great deal of insight regarding burden of proof. Specifically, as it applies to Commission proceedings, the Supreme Court has told us: (1) that burden of proof is a "substantial right" of the customers and (2) that burden of proof should be "rigidly enforced" by the Commission.

> The rules as to burden of proof are important and indispensable in the administration of justice, and constitutes a substantial right of the party of whose adversary the burden rests; they should be jealously guarded and rigidly enforced by the courts.[1]

3. The Supreme Court has also provided definition for the burden of proof.

> The burden of proof meaning the obligation to establish the truth of the claim by a preponderance of the evidence, rests throughout upon the party asserting the affirmative of the issue. The burden of proof never shifts during the course of the trial.[2]

As such, the burden of proof means that the proponent of higher rates in a Commission proceeding has the "obligation to establish the truth" of its need for the higher rates. In this regard, customers are given the benefit of the doubt that the utility only needs the lower rate and that the utility must "prove" that the higher rate is necessary. Therefore, if there is any question regarding the legitimacy of a cost or expense; if the Commission does not adequately understand an issue; or if the Company fails to adequately explain its need for the higher rate, then the utility has failed to meet its burden of proof.

[1] *Highfill v. Brown*, 320 S.W.2d 493 (Mo. 1959).
[2] *Clapper v. Lakin*, 123 S.W.2d 27 (Mo. 1938).

4. Finally, the Supreme Court has provided insight as to the implications to a party that fails to meet its burden of proof: "the failure of the plaintiff to sustain such burden ***is fatal*** to his or her relief or recovery."[3]

[3] *Id.*

II. NON-UNANIMOUS STIPULATION

5. On April 15, 2020, several parties filed a non-unanimous stipulation. On April 16, 2010, Public Counsel filed its objection to several of the provisions in that stipulation.

6. Commission Rule 4 CSR 240-2.115(2)(D) provides that a nonunanimous stipulation and agreement to which an objection is made is to be treated as a joint position of the signatory parties, except that no party is bound by the agreement.

7. As the Commission has previously held:

> The approach the Commission must take when considering a nonunanimous stipulation and agreement to which an objection is made is further described in a 1982 decision of the Missouri Court of Appeals. In State ex rel. Fischer v. Public Service Commission, the Court held that when considering a nonunanimous stipulation and agreement the Commission must recognize all statutory requirements, including the right to be heard and to introduce evidence. Furthermore, the Commission's decision must be in writing and must include adequate findings of fact.[4]

8. Given this requirement, the Commission shall issue findings of fact for all of the issues for which Public Counsel has objected to the non-unanimous stipulation.

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[4] *Report and Order*, Case No. ER-2011-0028, issued July 13, 2011, at pages 119-120 (citing to *State ex rel. Fischer v. Public Service Commission*, 645 S.W.2d 39 (Mo.App. 1982).

III. RETURN ON EQUITY

A. FINDINGS OF FACT

9. This issue concerns the rate of return that Empire should be authorized to earn on its rate base. Rate base includes items like generating plants, electric meters, wires and poles, substations and the trucks driven by Empire repair crews. In order to determine a rate of return, the Commission must determine KCPL / GMO's cost of obtaining the capital it needs.

10. Determining an appropriate return on equity, a component of the overall rate of return, is without a doubt the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock, if any, are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, in determining a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in Empire rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return that is unassailably scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market, without permitting an excessive rate of return on equity that would drive up rates for Empire's ratepayers. In order to obtain guidance about the appropriate return on equity, the Commission considers the testimony of expert witnesses.

11. Three financial analysts offered recommendations regarding an appropriate return on equity in this case. Empire witness Hevert recommends a return on

equity of 9.95% with a range of 9.80% to 10.60%.[5] Staff witness Chari recommends a return on equity of 9.25% with a range of 9.05% to 9.80%.[6] OPC witness Murray recommends a return on equity of 9.25% with a range of 8.50% to 9.25%.[7]

12. In addition to the recommendations of the return on equity witnesses, the Commission has historically also considered the national average return on equity in its consideration of an appropriate return on equity.

> The Commission mentions the average allowed return on equity not because the Commission should, or would slavishly follow the national average in awarding a return on equity to Ameren Missouri. However, Ameren Missouri must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.[8]

In this regard, Staff witness Chari testified that the national average return on equity for 2019 was 9.39%.[9]

13. On at least two previous occasions, the Commission expressed concerns with the assumptions included in Mr. Hevert's return on equity analyses. Specifically, the Commission indicated that Mr. Hevert's recommendation was "too high" primarily as a result of his use of long-term sustainable growth rate estimates that exceeded the growth outlook of the economy.

> However, Hevert's estimation of an appropriate ROE is <u>***too high***</u>. MIEC's witness, Michael Gorman explains that Mr. Hevert relied on long-term sustainable growth rate estimates in his DCF models that are higher than the growth outlook of the economy as a whole. As he explained, it is not rational to expect that utilities can grow faster than the demand of the economies they serve.[10]

[5] Exhibit 26, Hevert Direct, page 2.
[6] Exhibit 101, Staff Direct Report, page 5.
[7] Exhibit 210, Murray Direct, page 2.
[8] *Report and Order*, Case No. ER-2012-0166, issued December 12, 2012, page 67.
[9] Exhibit 108, Chari Rebuttal, pages 6-7.
[10] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70. (emphasis added).

Still again,

> Hevert's recommended return on equity is higher than the other recommendations in large part because he over-estimates future long-term growth in his various DCF analyses, making them ***too high*** to be reasonable estimates of long-term sustainable growth. When Hevert's long-term growth rates are adjusted to use more sustainable growth estimates based on published analyst's projections, his multi-stage DCF analysis produces a rate of return more in line with the estimates of LaConte and Gorman.[11]

14. The same problem seems to have occurred in his analysis in this case. As Staff witness Chari points out, while the expected long-term GDP growth rate is only 4.1%, Mr. Hevert utilized a growth rate of 5.8%.

> Mr. Hevert assumes, in his constant growth DCF model, that his electric proxy group's dividends will grow perpetually, at an average of 5.80%, a growth rate that is about 170 bps higher than the estimated long-term growth rate for the general economy. ***Assuming that utilities will grow at a higher rate than the overall economy is unrealistic, because it runs counter to basic economic principles: in the long run, companies will grow at a rate consistent with the long-term growth rate of the overall economy***.[12]

Given the continued problems with his use of inflated growth rates in the DCF analysis, the Commission again finds that Mr. Hevert's DCF is unreliable.

15. Additional problems are present in Mr. Hevert's other return on equity models. In addition to his DCF analysis that relies upon inflated growth rates, Mr. Hevert also utilized the CAPM, the empirical capital asset pricing model ("ECAPM") as well as a Risk Premium and expected earnings approach. Recently, the Federal Energy Regulatory Commission ("FERC") held that the risk premium and expected earnings approach are unreliable.

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[11] Case No. ER-2011-0028, *Report and Order*, issued July 13, 2011, at page 23. (emphasis added).

[12] Exhibit 108, Chari Rebuttal, page 7 (emphasis added). In his testimony, Mr. Chari points out that, while Mr. Hevert uses a growth rate of 5.8%, the long-term GDP growth rate is only 4.1%. See, Exhibit 108, Chari Rebuttal, page 7, footnote 7.

> Recently, FERC ruled that expected earnings model does not satisfy the requirements of the *Hope* case and therefore decided not to rely on that approach anymore. At the same time, FERC ruled risk premium models less reliable than the DCF and CAPM models and so decided to also stop relying on them for COE [cost of equity] estimation.[13]

Specifically, in regard to the expected earnings approach, FERC indicated that the approach, while more simplistic, does not comply with the Supreme Court's decision in *Hope*.[14] "[I]t is not appropriate to use the Expected Earnings model in our new base ROE methodology. . . [W]e find that relying on the Expected Earnings model would not satisfy the requirements of Hope."[15]

> While it may be true that the Expected Earnings model does not involve the same complexities as the market-based approaches, we find that this is because it does not reflect a utility's cost of equity. It is simpler because it does not consider the market price that an investor must pay to make its investment and other factors such as projected growth rates for the subject utility. Factors such as these—in particular the market price that an investor must pay for an investment, which is the basis for determining the return on that investment—are critical to determining a utility's cost of equity. While it may be simpler to use a model that does not consider such factors, doing so renders that model unable to effectively estimate the rate of return that investors require to invest in the market-priced common equity capital of a utility, which is the utility's cost of equity capital. We find that it is not appropriate to use a model that does not accurately measure the "return to the equity owner" as required by Hope merely because it may be simpler to administer. We are cognizant of the administrative burden that is placed on parties to evaluate models that are used in analyzing ROEs, but the mere simplicity of one model as compared to others does not justify using that model if it does not assist us in ensuring that returns to equity owners are just and reasonable.[16]

16. The FERC held that similar problems exist within the risk premium approach. "[W]e conclude that the additional robustness that the Risk Premium model

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[13] Exhibit 108, Chari Rebuttal, page 2 (citing to FERC Opinion 569, page 117, line 200).
[14] Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591 (1944).
[15] *Order on Briefs, Rehearing and Initial Decision*, Opinion No. 569, issued November 21, 2019, paragraphs 200 and 201 (Opinion No. 569).
[16] *Id.* at paragraph 204.

adds to the ROE determination is outweighed by the disadvantages of its deficiencies."[17] FERC reached this conclusion because while the DCF and CAPM analyses rely upon market-based data, the risk premium approach relies upon previous ROE determinations. Therefore, the risk premium approach embraces a measure of circularity.

> [T]he Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data. . . . While all models, including the DCF, feature some circularity, such circularity is particularly direct and acute with the Risk Premium model because it directly relies on past Commission ROE decisions.[18]

17. The Commission finds that the rationale expressed by FERC in its recent decision to be persuasive. Given the problems expressed in regards to the expected earnings and risk premium approaches, the Commission will similarly reject those methodologies.

18. That leaves Mr. Hevert's CAPM approach. In its decision, FERC indicated that the use of dividend-paying companies is a necessity.

> Using a DCF analysis of the dividend-paying members of the S&P 500 is a well-recognized method of estimating the expected market return for purposes of the CAPM model. The DCF analysis must be limited to the dividend-paying members of the S&P 500, rather than using all companies in the S&P 500, because a DCF analysis can only be performed on companies that pay dividends.[19]

19. In his analysis, however, Mr. Hevert included 84 companies that did not pay dividends.

> The principal flaw in Mr. Hevert's MRP is that he included companies that do not pay dividends. The constant growth DCF model assumes dividend payment. Staff discovered 84 companies that do not pay

[17] Opinion No. 569, paragraph 340.
[18] *Id.* at paragraphs 342-343.
[19] *Id.* at paragraph 260.

> dividends within the S&P 500 company list that Mr. Hevert used to develop his recommendation. This flaw inflated Mr. Hevert's MRPs.[20]

20. The Commission agrees with the findings of FERC as well as the testimony of Staff and finds that Mr. Hevert's inclusion of companies in his CAPM analysis that do not pay dividends to be problematic and should be avoided.

21. Next, Mr. Hevert argues that Empire's return on equity should be increased to account for Empire's small size. While Empire, on a stand-alone basis may be smaller than other utilities, Empire does not exist as a stand-alone entity. As Staff points out, Empire is one utility within the larger Algonquin / Liberty Utilities company.

> In his estimation of the size premium, Mr. Hevert assumed that Empire is a standalone company. This is a wrong assumption because since Empire merged with Algonquin Power and Utility Corporation ("APUC"), it ceased to be a standalone company. Empire no longer issues its own debt; it now relies on Liberty Utilities Corporation ("LUCo") and ultimately, APUC for all its financing. Empire is now a private company with all its stocks held and traded by APUC. This means that any size premium for Empire, if at all, should be based on APUC's market capitalization of $8.2 billion.[21]

Given its existence as part of a large corporation, Mr. Hevert's assertion is faulty.

22. Finally, as well as the numerous flaws in his analyses, Mr. Hevert's recommendation is also problematic. As mentioned, according to Regulatory Research Associated, the national average return on equity for 2019 was 9.39%.[22] Mr. Hevert's 9.95% is 56 basis points higher than the national average. As Staff points out:

> Mr. Hevert's recommended authorized ROE of 9.95% is too high. An authorized ROE of 9.95% is 56 basis points ("bps") higher than the 2019 national average authorized ROE of 9.39%. There were six fully litigated vertically integrated electric cases in the U.S.A. in 2019, of which five utilities were authorized 9.50% or less, and one was authorized 10.00%. Even the one case, involving DTE Electric Co., which was awarded a

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[20] Exhibit 108, Chari Rebuttal, pages 9-10 (emphasis added).
[21] Exhibit 108, Chari Rebuttal, page 12.
[22] Exhibit 101, Staff Direct Report, page 18.

> 10.00% authorized ROE was unique; the utility was authorized a capital structure with a far lower common equity ratio than the other five cases. It is therefore, implausible for Mr. Hevert to recommend such a high authorized ROE for Empire.[23]

23. In contrast, Staff's analysis does not suffer from the same infirmities as Empire's analysis. First, Empire avoided the methodologies that FERC found to be problematic. Specifically, Staff avoided the risk premium and expected earnings approaches in favor of a DCF and CAPM analysis.[24]

24. In regards to its growth rate in its DCF, "Staff considered the 10-Year and 5-Year historical earnings per share ("EPS") for each of the comparable companies and also the 5-Year SNL projected EPS. The 10-year and 5-year historical average were 3.66% and 3.11%, respectively."[25] Staff explains that its growth rate should be below the 4.1% expected growth in the domestic economy.

> For developed countries like the United States, electricity usage is projected to be even lower than economic growth due to decrease in the use of electricity. The U.S. and other developed countries are moving away from manufacturing-based economies to service-based economies. Service-based economies tend to use less electricity than economies with high levels of industrial activity.[26]

25. In regards to its CAPM approach, Staff was careful to only include dividend-paying companies. Specifically, Staff's proxy group includes only companies that pay dividends.[27]

26. While Staff recommends a return on equity of 9.25% based upon its DCF and CAPM approaches, Staff inflates the top end of its range to 9.80% by relying on the

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[23] Exhibit 108, Chari Rebuttal, pages 6-7. Specifically, while DTE was authorized a return on equity of 10.00%, that return was applied to a capital structure that consisted of only 37.94% common equity. In contrast, the other authorized returns for 2019 were applied to capital structures which included 49.46% to 53.00% common equity. (See, Exhibit 108, Chari Rebuttal, page 7, footnote 6).
[24] Exhibit 101, Staff Direct Report, page 4.
[25] *Id.* at page 14.
[26] *Id.* at page 15.
[27] *Id.* at page 13.

Commission's decision in the 2017 Spire case.[28] There are numerous problems associated with Staff's consideration of the Spire decision. First, the Spire decision is now over 26 months old. Much has happened in the U.S. economy since that time. Second, while the Spire decision concerns the return on equity for a gas utility, the Commission is tasked in this case with setting the return on equity for an electric utility. Finally, by relying on a previous Commission return on equity decision, the Commission inevitably finds itself engaging in circular thinking. As FERC indicated when considering the appropriateness of various return on equity methodologies, the risk premium approach does not rely on market data, but rather relies on previous Commission decisions. Therefore, it directly embraces "circularity." Similarly, by attempting to extract an appropriate return on equity by foregoing market based data in favor of a single Commission decision from 2017 also engages in circularity.

B. CONCLUSIONS OF LAW

27. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate to the particular application' (quoting *Southwestern Bell Telephone Company v. Arkansas Public Service Commission,* 593 S.W. 2d 434 (Ark 1980).[29]

[28] Exhibit 101, Staff Direct Report, page 5.
[29] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission*, 706 S.W.2d 870, 880 (Mo.App. W.D. 1985).

Furthermore,

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[30]

28. In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a "precise science":

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of 'precise science,' because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[31]

DECISION:

29. Based on the evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.25 percent is a fair and reasonable return on equity for Empire.

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[30] *Id.*

[31] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo.App. W.D. 2005).

IV. CLASS COST OF SERVICE ISSUES

30. In this case, class cost of service studies were presented by 3 parties: Empire, Staff and MECG. "The purpose of a CCOS is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service."[32] By allocating each cost in a rational manner to the individual rate classes, one can determine the cost of service for each rate class. In the case at hand, class cost of service issues surrounding the allocation of: (1) fixed production-related costs; (2) distribution plant accounts 364, 366 and 368; (3) primary and secondary distribution plant costs; and (4) general plant costs have arisen.

A. FIXED PRODUCTION RELATED COSTS

Issue 2(z): How should production-related costs be allocated to each rate class?

31. In general, utilities incur three categories of costs: (1) customer-related costs: costs associated with connecting customers to the distribution system, metering usage and other customer support functions (i.e., meter reading, billing, postage and customer service expenses); (2) energy-related costs: costs that tend to change with the amount of electricity sold (i.e., fuel, fuel handling, and interchange power costs); and (3) demand-related costs: costs associated with meeting maximum electricity demands.

32. It is well established that the electric industry is very capital intensive. As Mr. Lyons recognizes, "[p]roduction plant is the largest component of the Company's rate base, representing 44.4 percent of total utility plant."[33] Therefore, the single largest issue within an electric class cost of service study involves the allocation of the utility's investment in generating units (fixed production plant costs).

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[32] Exhibit 26, Lyons Direct, page 8.
[33] *Id.* at page 20.

33. While there are different methods utilized for allocating generation fixed costs, the difference in these methodologies generally concerns the extent to which the methodology treats production plant as an energy-related cost (focused on meeting system energy usage) or a demand-related cost (focused on meeting system peak demand).

34. In the case at hand, both Empire and MECG utilize the Average and Excess ("A&E") method for allocating fixed production plant related costs.[34] As described by Empire witness Lyons, the A&E approach allocates "a portion of production plant based on energy consumption and the remaining portion based on peak demands."[35] Given this, the A&E approach recognizes that production plant is used to meet not only each class's peak demands, but also each class's energy needs.

In contrast, Staff recommends the use of the Highest Hours approach.[36] Under this approach, Staff sorts Empire's highest hourly peaks for the year and then allocates fixed production plant costs based upon each class' contribution to the peak in each of a specified number of hours. In this case, Staff considered utilizing the highest 12, 51, 100, 135, and 310 hourly peaks before ultimately settling on the top 100 highest peaks.[37] Therefore, under Staff's approach, each class is allocated production plant costs based upon its contribution to the highest 100 peaks that Empire experienced.

35. The evidence indicates and the Commission finds that the A&E approach appropriately recognizes that fixed production plant related investment is used to meet

[34] Exhibit 350, Maini Direct, page 19; Exhibit 26, Lyons Direct, page 21.
[35] Exhibit 26, Lyons Direct, page 21 (emphasis added).
[36] Exhibit 104, Staff Class Cost of Service Report, page 26.
[37] Exhibit 104, Staff Class Cost of Service Report, page 27.

not only each class's peak demands, but also its energy needs. As the Commission has previously found:

> An A&E allocation method considers both the maximum rate of use (demand) and the duration of use (energy). The A&E method conceptually splits the system into an average component and an excess component. The average demand is the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system excess demand is the difference between the system peak demand and the system average demand. The average demand is allocated to the various classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak or peaks is then allocated to customer classes on the basis of a measure that represents their peaking or variability in usage.[38]

36. Given the inherent logic inherent in the approach (treating production plant as both an energy and a demand related investment), the A&E fixed production allocator has been well accepted in the electric utility industry. As indicated, the A&E approach was utilized in this case by both Empire and MECG. In addition, the A&E approach is utilized by all of the Missouri electric utilities.[39] Furthermore, the A&E approach has previously been utilized by not only this Commission,[40] but also a vast majority of the state utility commissions in vertically integrated states.[41]

37. In contrast, the Commission finds that Staff's Highest Hours approach has not been utilized by any utilities or state utility commissions. Staff concedes this fact.[42]

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[38] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, page 82.
[39] Exhibit 350, Maini Direct, page 19.
[40] *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, page 87.
[41] In its Initial Brief (pages 19-22), MECG detailed a number of state utility commissions that utilize the A&E fixed production plant allocator including Louisiana, Oklahoma, Texas, Arkansas, Colorado, District of Columbia, FERC, Hawaii, Pennsylvania, Maryland and Connecticut.
[42] Staff Responsive Brief, page 11.

Rather, Staff's Highest Hours approach was only recently postulated in a Regulatory Assistance Project publication.[43]

The fact that the Highest Hours approach has not been accepted by other state utility commissions is an important consideration. While the Commission is setting rates for Empire's customers, it is not setting those rates in a vacuum. Rather, as will be discussed in more detail, *infra*, the Commission is cognizant of the competitiveness of Empire's industrial rates. The Commission finds that, by taking an approach that is more punitive to high load factor customers at the same time that most other states are utilizing the more measured A&E approach will lead to industrial rates that are increasing uncompetitive. This has the potential to place Empire industrial customers at a competitive disadvantage and hinder the Empire service area's ability to attract or retain industrial customers and jobs.

38. Staff's latest approach also reflects a constantly changing approach to allocating fixed production plant related costs. At the beginning of the last decade, Staff argued on behalf of the Peak & Average approach.[44] Shortly thereafter, Staff advocated for the Base / Intermediate / Peak approach to allocating fixed production costs.[45] Just last year, Staff again changed its approach to what it termed a "functionalized approach."[46] Now, Staff has again changed its approach to the Highest Hour approach.[47] Again, Staff concedes that its approach has been subject to much change.[48]

[43] Exhibit 104, Staff Class Cost of Service Report, page 26.
[44] See, Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at pages 85-86.
[45] See, Case No. ER-2016-0285, *Report and Order*, issued May 3, 2017, at page 50.
[46] Exhibit 104, Staff Class Cost of Service Report, page 26.
[47] *Id.*
[48] Staff Responsive Brief, page 11.

The constantly changing approach to allocating fixed production plant costs, as invited by Staff, has the tendency to introduce increasing levels of regulatory uncertainty, not only for Empire, but also its customers. Specifically, by constantly changing allocators, the Commission may unintentionally cause inter-class subsidies to appear, disappear and then reappear. This causes uncertainty, but also provides for the potential for rate volatility for Empire's customer classes.

39. In addition to being novel and untested, the Commission further finds that the Highest Hours approach is largely arbitrary in application. The arbitrariness is demonstrated by the fact that, by choosing a higher or lower number of hourly peaks, one can actually manipulate the approach to create the result that it desires. That is, by focusing on a higher number of peaks, one can easily lessen the impact of the summer air conditioning / winter space heating loads that are largely driven by lower load factor classes. This fact is shown by the dramatic difference in Staff's allocation of production plant investment to the classes based upon whether it uses 12, 51, 100, 135 or 310 hours.[49]

In this case, Staff relied upon each class's contribution to Empire's highest 100 peaks. That said, however, the evidence shows that Empire considers the addition of generating capacity based simply on two peaks: its highest winter and highest summer peaks.[50] Therefore, Staff's use of 100 peaks is arbitrary and serves to shift costs from low load factor classes to higher load factor classes.

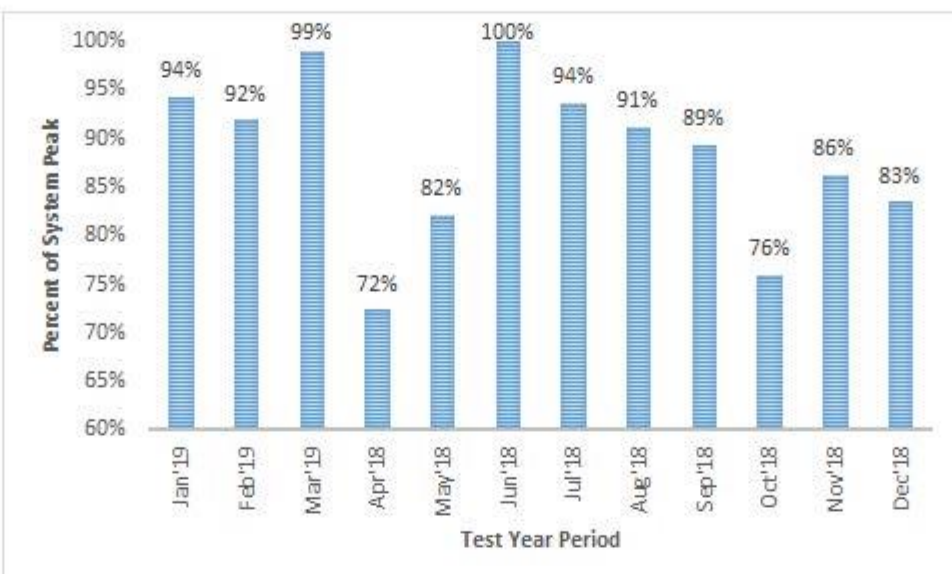
40. As mentioned, the A&E approach is inherently logical and has seen widespread acceptance among utilities and state utility commissions. Given these facts

[49] See, Exhibit 104, Staff Class Cost of Service Report, page 27.
[50] Exhibit 351, Maini Rebuttal, page 7.

as well the untested and arbitrary nature of the Highest Hours approach, the Commission decides that the A&E approach most appropriately allocates fixed production plant costs among Empire's customer classes.

41. That said, however, the record shows that there are different variations on the A&E approach. Specifically, since class peak demand is a necessary component of the A&E methodology, the A&E approach may change based upon whether one uses the single largest monthly peak, the monthly peak for all 12 months or simply the largest monthly peaks that approximate the annual peak. In this case, while Empire utilized all 12 monthly peaks,[51] MECG utilized the six monthly peaks that fall within 90% of the annual peak. This includes three monthly peaks during Empire's summer peak (June through August) and three during Empire's winter peak (January through March).[52]

Figure 4: Liberty-Empire Missouri's Monthly Peak Demands As a Percent of Annual Peak



Source: Exhibit 350, Maini Direct, page 17.

[51] Exhibit 26, Lyons Direct, page 21.
[52] Exhibit 351, Maini Rebuttal, page 7.

42. The Commission finds that not all monthly peaks factor into Empire's decision to construct additional capacity. In performing its Integrated Resource Plan, Empire does not rely upon all 12 monthly peaks. Rather, Empire only considers two peaks - the highest winter and highest summer peaks.[53] Given that only these monthly peaks determine whether fixed production plant related costs are incurred, it also makes sense that these peaks be utilized for allocating these costs among the classes. For this reason, the Commission finds that MECG's approach best allocates costs in a manner consistent with how those costs are incurred.

Empire's approach, on the other hand, would also consider peaks in April and October which represent only 72% and 76% of the annual peak. These peaks, since they are so far below the annual peak, play virtually no role in the decision to add capacity and incur production plant related costs. Therefore, since they play a limited role in the decision to add capacity and incur these fixed costs, these ancillary peaks should also play no role in the allocation of these costs among the classes. For this reason, the Commission finds that the 6NCP variation of the A&E methodology best allocates fixed production plant-related costs among Empire's customer classes.

B. CLASSIFICATION OF DISTRIBUTION COSTS

Issue (2)(aa): How should plant accounts 364, 366 and 368 be classified?

43. Distribution plant costs associated poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices and line transformers are booked in Accounts 364-368.[54] These costs must then be classified as

[53] *Id.*
[54] Exhibit 350, Maini Direct, page 22.

either customer or demand-related.[55] In general, there are two methods for segregating the customer-related portion of these costs from the demand-related portion: (1) the minimum size approach utilized by Empire and MECG and (2) the zero intercept approach utilized by Staff.

> The Minimum-size Method assumes that a minimum size distribution system can be built to serve minimum demand requirements of customers. . . . The approach is consistent with the methodology described in the NARUC manual:
>
> > Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility.[56]

44. In contrast to the minimum size approach utilized by both Empire and MECG, Staff advocated for the zero intercept approach.

> The concept behind a Zero-Intercept Cost study is to seek to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.[57]

While the NARUC allocation manual finds that both approaches are acceptable, it does state that the differences between the two methodologies should be "relatively small."[58]

45. Contrary to the expected small differences, the minimum size and zero intercept approaches in this case result in dramatic differences. For instance, under Empire's minimum size approach, 53.1% of the costs in Account 364 are classified as

[55] *Id.*
[56] Exhibit 26, Lyons Direct, pages 17-18.
[57] Exhibit 104, Staff Class Cost of Service Report, page 28.
[58] Exhibit 351, Maini Rebuttal, page 14.

customer-related while only 22.6% of such costs are classified as customer related under Staff's zero intercept approach.[59] Still again, Empire's methodology classifies 43% of Account 368 costs as customer-related while Staff's methodology only classified 9.8% of such costs as customer-related.[60] Thus, despite the expectation that differences between the two methodologies would be "relatively small", dramatic differences arise between Staff's zero-intercept approach and the minimum size approach relied upon by Empire and MECG.

46. The evidence shows, and the Commission finds, that Staff's methodology either leads to illogical conclusions or fails to consider certain data. For instance, "Staff's regression analysis [for Account 368] shows that the 'no-load' number is negative, which suggests that a negative percentage of costs are customer-related. Such a result is not reliable."[61] As Empire witness Lyons pointed out, Staff's methodology considered "limited data": a 15 kVa overhead transformer cost, and a 25 kVA underground transformer cost.[62] "This would help to explain Staff's study results which show a negative zero-intercept."[63]

Furthermore, in regards to Account 364, Mr. Lyons pointed out that "Staff's methodology does not consider the cost of anchors and guys."[64] Inclusion of such costs would have resulted in higher customer-related costs.[65] Similarly, in Account 366, "Staff's methodology does not consider the cost of vaults and pedestals."[66]

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[59] *Id.* at page 15. See also, Exhibit 28, Lyons Rebuttal, page 25.
[60] *Id.*
[61] Exhibit 351, Maini Rebuttal, page 15.
[62] *Id.*
[63] *Id.*
[64] Exhibit 28, Lyons Rebuttal, page 26.
[65] *Id.*
[66] *Id.*

In its surrebuttal testimony, does not attempt to justify its conclusion, but instead seeks to excuse the numerous problems in its classification of distribution costs on the basis that data was "limited" which precluded a more "robust" analysis.[67]

47. Given the obvious problems with Staff's zero-intercept approach, the Commission finds that Empire's minimum size approach for classifying distribution-related costs should be utilized.

C. ALLOCATION OF DEMAND-RELATED DISTRIBUTION COSTS

Issue 2(bb): How should primary and secondary distribution plant costs be allocated to each rate class?

48. In the previous issue the Commission decided the most appropriate manner for classifying distribution costs as either customer or demand-related. Once the costs have been classified as customer or demand related the Commission must decide the best way to allocate the customer and demand-related costs to the various classes. All parties agree that the customer-related portion of these distribution costs should be allocated on the basis of the number of customers.[68] The parties disagree, however, on the appropriate method for allocating the demand-related portion of distribution costs.

49. MECG asserts that the distribution system must be sized to meet the customer's single largest peak (1 NCP) within the year. "[W]hen designing primary and secondary distribution feeders, sufficient conductor and transformer capacity must be available to meet the maximum customer loads at the primary and secondary distribution levels, whenever the maximum demands occur."[69]

[67] Exhibit 135, Kliethermes Surrebuttal, page 3.
[68] Exhibit 26, Lyons Direct, page 25. Exhibit 104, Staff Class Cost of Service Report, page 28.
[69] Exhibit 351, Maini Rebuttal, page 10.

In contrast, Empire proposes that the demand-related portion of these distribution costs should be allocated among the customer classes based upon each class' contribution to the average of the six largest (6 NCP). Empire asserts that the 6 NCP methodology reflects how the Company plans for distribution capacity.[70]

Finally, Staff allocates the demand-related portion of distribution costs based upon the sum of coincident peaks approach.[71]

50. The Commission finds that MECG's approach is the best method for allocating the demand-related portion of distribution costs. Given that the distribution system is sized to meet the customer's single largest peak, no matter when it occurs, it necessarily will meet any other peaks. In other words, all other peaks are necessarily subsumed within the single largest peak. "By sizing [the distribution system] in this manner, the distribution infrastructure necessarily accommodates all demands lower than the maximum demands."[72] Recognizing then that the distribution system is sized and costs incurred to meet a class' single largest peak, the demand portion of these distribution costs should be allocated to each class based upon the class' contribution to the single largest peak.

Additionally, the 1 NCP approach also reflects the manner in which these costs are collected for the demand-metered classes. Specifically, Empire collects its distribution costs from these classes by using a ratcheted facilities demand charge.[73] The use of a ratcheted facilities demand charge means that Empire collects its distribution costs from these customers based upon the single largest peak that occurred in the

[70] Exhibit 28, Lyons Rebuttal, page 27.
[71] Exhibit 104, Staff Class Cost of Service Report, page 29.
[72] Exhibit 351, Maini Rebuttal, page 10.
[73] *Id*. See also, Exhibit 355.

previous 12 months. "[T]he primary reason that the facility demand is ratcheted in LP rates (i.e., based on the maximum customer demand over a twelve month period) is to recognize that the distribution facilities being used, are sized to accommodate the maximum demands, whenever they occur."[74] Recognizing that Empire collects the demand-related portion of distribution plant based upon a customer's single largest peak, it is logical that these costs should be allocated between classes in a similar manner. "Each class' single non-coincident peak demand is therefore a more reasonable indicator to reflect the cost causing characteristic of building the distribution-related infrastructure."[75]

<u>D.</u> <u>ALLOCATION OF GENERAL PLANT COSTS</u>

Issue 2(cc): How should general plant facility costs be allocated to each rate class?

51. On the final class cost of service issue, Empire and MECG are in full agreement on the allocation of general plant costs. Specifically, Empire and MECG both utilize allocators that are logically related to the manner in which Empire incurs these general plant costs.[76] For instance,

> General Plant facilities are generally used by the Company employees. Accordingly the General Plant costs were allocated based on a composite of labor-related O&M expenses. The Company's approach is generally consistent with the allocation method for these costs described in the NARUC manual.[77]

Similarly, Empire utilized an approach to allocating A&G costs that best reflects how those costs are actually incurred.

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[74] Exhibit 351, Maini Rebuttal, page 10.
[75] *Id.*
[76] Empire Responsive Brief, page 21; MECG Initial Brief, page 30 ("Empire allocated such costs on a rational basis that reflects the manner in which such costs are incurred.").
[77] *Id.* (citing to NARUC Electric Utility Cost Allocation Manual, page 105).

> Labor related A&G expenses (such as Accounts 920 through 926) are allocated based on a composite of labor-related O&M expenses, while Plant-related A&G expenses are allocated based on a composite Total Plant allocation. The Company's approach is generally consistent with the allocation method for these costs described in the NARUC manual.[78]

52. In contrast, Staff simply labeled such costs as "miscellaneous and unassignable" and allocated these costs on the basis of an energy allocator that is punitive to high load factor rate classes. Noticeably, in recent Empire rate cases, Staff used a more logical allocator. For instance, in Empire's last rate case, Staff allocated General Plant on the basis of the gross production, transmission and distribution plant allocator. Similarly, materials and supplies were not allocated in the last case based upon the energy allocator, but instead on the basis of net plant.[79]

53. Staff's decision to allocate these general plant costs using the energy allocator rather than an allocator that better reflects the manner in which the costs are incurred results in significant differences. For instance, by using class energy to allocate general plant, the residential class is only allocated 39% of these costs. In contrast, the residential class is allocated 70.6% of these costs in Empire and MECG's analysis.[80] Still again, by using class energy to allocated A&G costs, Staff has allocated only 39.9% of these costs to the residential class. In contrast, the residential class is allocated 68.8% of such costs under the Empire and MECG studies.[81]

54. The Commission finds that these general plant costs are incurred regardless of class energy consumption. As such, since these costs are incurred regardless of energy usage, it is not logical to then allocate these costs based upon class

[78] (citing to NARUC Electric Utility Cost Allocation Manual, pages 106-107).
[79] Exhibit 351, Maini Rebuttal, Schedule KM-2.
[80] Exhibit 28, Lyons Rebuttal, page 30.
[81] *Id.*

energy usage. In contrast, the methodologies utilized by Empire better reflects the manner in which these costs are incurred. As such, the Commission adopts the approach recommended by Empire for allocating general plant costs.

V. REVENUE ALLOCATION

Issue 2(d): How should Empire's revenue requirement be allocated amongst Empire's customer rate classes (Class revenues responsibilities)?
Issue 2(r): How should any revenue requirement increase or decrease be allocated to each rate class?

55. Although Staff's class cost of service approach is different from the approaches utilized by Empire and MECG, the conclusions reached are similar. As Staff admits, "[t]he three CCOS Studies submitted by Staff, Empire, and MECG in this matter, utilizing different allocation methodologies, still reach similar conclusions regarding the directions of the shifts between and among customer classes."[82]

Although the magnitude differs, each class cost of service study demonstrates the existence of a residential subsidy. For instance, while Empire earned an overall rate of return of 6.11%, it was only earning 2.90%, 2.62% or 5.46% from the residential class under the Empire, MECG and Staff studies respectively.[83] On the other hand, the commercial (CB, SH, GP and TEB) and industrial (LP and SC-P) classes are paying rates above cost of service in order to accommodate the residential subsidy.

	Empire[84]	MECG[85]	Staff[86]
RG – Residential	2.90%	2.62%	5.46%
CB – Commercial	8.23%	8.16%	11.31%
SH – Small Heating	7.39%	7.12%	11.31%
GP – General Power	11.44%	12.19%	11.11%
SC-P Praxair	12.78%	15.28%	11.38%
Total Electric Bldg	11.46%	11.37%	11.11%
PFM - Feed Mill	10.59%	10.56%	-36.92%
LP - Large Power	8.34%	9.52%	10.88%

[82] Staff Responsive Brief, pages 11-12.
[83] See, Table 1.
[84] Exhibit 350, Maini Direct, page 31 (based upon Lyons Direct, Schedule TSL-9). Empire subsequently agreed with certain adjustments to "firm up" the revenues for the interruptible SC-P class and to more appropriately allocate the interruptible credits for this class. This has the effect of increasing the earned return for the SC-P class. (See, Exhibit 26, Lyons Rebuttal, page 10 and 34).
[85] Exhibit 350, Maini Direct, page 31.
[86] Exhibit 121, Lange Rebuttal, page 17. Staff's quantification reflects its recommendation to consolidate the GP and TEB classes as well as the CB and SH classes.

MS – Miscellaneous Svc.	-5.21%	-4.94%	28.70%
SPL – Municipal Ltg.	1.77%	1.99%	28.70%
PL – Private Ltg.	26.95%	26.48%	28.70%
LS – Special Ltg.	-6.47%	-7.18%	28.70%
Total Company	6.11%	6.11%	6.11%

56. The existence of a residential subsidy, as reflected in each of the class cost of service studies, is not surprising. In Case No. ER-2014-0351, the Commission similarly found the existence of a residential subsidy and took steps to eliminate 25% of that subsidy.[87] Similarly, in Empire's last rate case, the Commission approved a settlement by which a revenue neutral shift of costs to the residential class was enacted.[88] Nevertheless, the residential subsidy not only persists, it has actually grown. Specifically, in 2014, the Commission quantified the residential subsidy at 8.1%.[89] Now, despite the steps taken in each of those last two cases, the residential subsidy has increased to 16.8%.[90]

57. In addition to the growing residential subsidy, another concern exists. In the 2014 case, the Commission expressed concern that, as a result of the residential subsidy, Empire's industrial rates were inflated to the point of being uncompetitive.

> Competitive industrial rates are an important factor in helping to retain and expand industry within the utility's service area. Business retention and expansion result in positive impacts on local economy and employment. Further, if businesses relocate or expand in Empire's service area, it has the potential of lowering costs for customers as the fixed costs are spread over larger amount of billing determinants. The converse is also true – if businesses shift operations from Empire's area, the remaining customers bear the burden of the same fixed costs but over a smaller amount of billing determinants thereby increasing rates for all customers. Thus, the Commission should be cognizant of how its decisions affect industrial rates.[91]

87 *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, page 18.
88 *Report and Order*, Case No. ER-2016-0023, issued August 10, 2016, Attachment A, page 9.
89 *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, page 18.
90 Exhibit 350, Maini Direct, page 35.
91 *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, page 18.

58. The Commission finds that the situation with Empire's industrial rates has not improved over the last 6 years. Given the increase in the residential subsidy since 2014, it is not surprising that Empire's industrial rates have become even more uncompetitive. Specifically, according to the EEI Typical Bills and Average Rates Report, while Empire's industrial rates were 16.7% above the national average just five years ago, Empire's industrial rates are now 21.1% above the national average industrial rate.[92]

59. The uncompetitiveness of Empire's industrial rates is also demonstrated by ranking Empire's industrial rates directly with those of other electric utilities. Of the 95 investor-owned electric utilities operating in 28 Midwest and Central states, Empire's industrial electric rate is 12th highest.[93] This conclusion is supported by confidential testimony of MECG witness Chriss. As Mr. Chriss indicates, as an employee of Walmart, he is able to benchmark individual utility rates against those of other utilities or against regional / national averages. Given its operations in all 50 states and the District of Columbia, Walmart is "able to easily benchmark our utility cost in one market against other utilities in that market as well as against regional and national benchmarks."[94] Based upon these comparisons, Mr. Chriss indicates that Walmart's experience supports the conclusions reached in the EEI data.

60. In its testimony, Staff,[95] Empire[96] and MECG[97] all indicate that steps should be taken to address the residential subsidy. Specifically, MECG recommends that

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[92] Exhibit 350, Maini Direct, page 9 (citing to EEI Typical Bills and Average Rate Report, Summer 2019).
[93] *Id.* at page 9 and Schedule KM-2.
[94] Exhibit 353, Chriss Surrebuttal, page 5.
[95] In its direct testimony, Staff recommended that any rate reduction be assigned to the CB/SH, GP/TEB, and LPS rate schedules. (Exhibit 104, Staff Class Cost of Service Report, page 32). In its rebuttal testimony, Staff corrected an error in its class cost of service study and, as a result, agreed that the SC-P rate class should also receive a portion of any rate reduction. (Exhibit 121, Lange Rebuttal, page 18).

the Commission, as it did in the 2014 Empire case, eliminate 25% of the residential subsidy.[98] As shown in the following table, such a movement would lead to a 4.2% increase for the residential class and improve the competitiveness of all commercial and industrial classes.

	Revenue Shift (in thousands)	% Shift
RG – Residential	+$9,030	4.2%
CB – Commercial	-$841	-1.9%
SH – Small Heating	-$101	-1.0%
GP – General Power	-$4,310	-5.1%
SC-P – Praxair	-$239	-5.4%
TEB – Total Electric Bldg.	-$1,674	-4.6%
PFM – Feed Mill	-$3	-4.5%
LP – Large Power	-$1,846	-3.0%
MS – Miscellaneous Svc.	+$1	7.5%
SPL – Municipal Ltg.	+$259	11.9%
PL – Private Ltg.	-$445	-10.9%
LS – Special Ltg.	+$77	58.8%

Source: Exhibit 350, Maini Direct, page 35.

61. Given the conclusions reached by all of the class cost of service studies, as well as the increasingly uncompetitive nature of Empire's industrial rates, the Commission finds that it is appropriate to eliminate 25% of the residential subsidy (4.2%) as recommended by MECG. The Commission further finds that such a step would not be punitive to the residential class.

Consistent with the Commission's finding from previous cases, the recommended 4.2% shift is not punitive to the residential class. Empire has agreed, through the Non-Unanimous Stipulation, to no rate change. Therefore, MECG's proposed revenue neutral shift would only result in an overall residential increase of 4.2%. In its original filing

[96] Exhibit 26, Lyons Direct, pages 2-3.
[97] Exhibit 350, Maini Direct, page 35.
[98] Exhibit 350, Maini Direct, page 35.

Empire sought an increase for the residential class of 5.8%.[99] Therefore, even after the proposed revenue neutral shift, residential customers would still see a smaller rate increase than they were initially expecting from this case.

62. While Empire, Staff and MECG all agree that Empire's residential rates are heavily subsidized, Public Counsel disagrees. Instead, Public Counsel simply dismisses all of the studies.[100] "Public Counsel cannot overemphasize enough how the number of estimated billings makes the parties' class cost-of-service studies so unreliable that they are of no use for designing class rates in this case."[101] Interestingly, while claiming that the short-term increase in estimated billings made the class cost of service studies "unreliable", Public Counsel never bothered to explain the connection between estimated billings and class cost of service studies that makes the studies "unreliable".

63. On the other hand, Empire convincingly rebuts Public Counsel's assertion that the class cost of service studies are unreliable. Specifically, Empire points out that a class cost of service study relies upon "aggregate data" and not the "individual customer data" that would be affected by estimated bills.

> We appreciate Staff's concerns regarding the data quality issues; however, the Company believes that the data quality issues do not result in a material impact on the results of the CCOS nor render them unreliable. The CCOS relies on aggregate customer data rather than individual customer data, and any concerns with individual customer data do not appear to impact the results of the CCOS.[102]

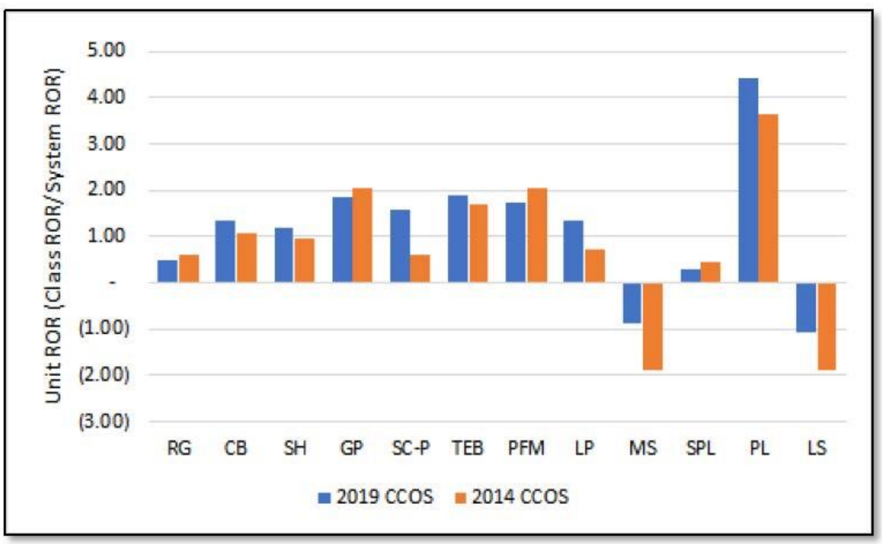
[99] Richard Direct, Schedule SDR-9.
[100] In rebuttal testimony, Public Counsel indicated that it was "tentatively aligned with Staff's initial recommendations." (Exhibit 208, Marke Rate Design Rebuttal, page 5). Now, after tentatively aligning itself with Staff's methodologies and positions, Public Counsel suggests that "Staff's 'highest hours' methodology is no more of an impractical academic theory than the 'average and excess' approach MECG advocates." (Public Counsel Responsive Brief, page 19).
[101] Public Counsel Responsive Brief, page 17.
[102] Exhibit 29, Lyons Surrebuttal, page 10.

Staff also appears to recognize the distinction between individual customer data, which is used for billing, and aggregate data which is used for class cost of service studies. "[T]he total level of billing determinants for Staff's test period ***will not change based on the number of estimated bills***."[103]

64. Furthermore, Empire showed, despite Public Counsel's assertion that the studies are unreliable, that the class cost of service studies in this case deliver comparable results to the studies conducted in 2014.

> This is substantiated by the results of the Company's CCOS in its prior rate case proceeding in 2014, as shown in Figure 1 (below). The Figure shows the unit rate of return for each rate class in this proceeding is generally consistent with the unit rate of return in the prior rate case proceeding in 2014.[104]

Figure 1: Comparison of Unit Rate of Return



Source: Exhibit 29, Lyons Surrebuttal, page 11.

Given this, the Commission finds that Public Counsel's assertion that the class cost of service studies in this case are unreliable is without merit.

[103] Exhibit 165, Kliethermes Supplemental Rebuttal, page 3.
[104] *Id.* at pages 10-11.

65. Next, Public Counsel encourages the Commission to actually <u>increase</u> the residential subsidy to account for the effects of the Covid-19 pandemic.[105] Claiming that commercial and industrial customers can simply "shut down" to avoid electric rates,[106] Public Counsel asserts that a "residential customer cannot 'shut down'."[107] Given this, Public Counsel suggests that the Covid-19 pandemic is disproportionately impacting residential customers.[108]

66. Contrary to Public Counsel's assertion, the Commission finds that no specific class of customers is being impacted more than another from the pandemic. As MECG witness Meyer points out:

> It is unquestioned that the current pandemic is having an effect on all aspects of the Empire customer base. As a result of various state and local lockdown orders, many commercial and industrial customers have had to close their doors. Still others are suffering from an inability to obtain necessary raw materials required in their manufacturing process. Others, like petroleum pipelines, are suffering from a tremendous decline in customer demand. Clearly then, commercial and industrial customers are suffering from the effects of the Covid-19 pandemic.[109]

Mr. Meyer's assertion that the pandemic is affecting large commercial and industrial customers is also demonstrated by the steep decline in the Dow Jones Industrial Average. As Mr. Meyer points out, as of April 17, 2020 "[t]he Dow Jones average closed approximately 11,000 points down from its 52 week high on March 23, 2020."[110] Given this, because of forced closures or reduced production, many large customers have seen their stock prices decline to the point of speculated bankruptcies.

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[105] Public Counsel Responsive Brief, page 21 ("[B]ecause of the unprecedented turmoil in the economy caused by the COVID-19 national emergency, . . . Public Counsel primarily recommends that, if the Commission finds that Empire's rates should be reduced, it is only the residential customer class' rates that should be reduced.").
[106] Public Counsel Responsive Brief, page 19.
[107] *Id.*
[108] See, Public Counsel Initial Brief, page 25.
[109] Exhibit 354, Meyer Supplemental Surrebuttal, page 5.
[110] *Id.*

67. Also contrary to Public Counsel's assertions, commercial and industrial customers have virtually no ability to avoid their electric bills. Since 90.9% of the residential revenue requirement is collected through energy charges, residential customers have a large degree of control over their electric bill simply by adjusting consumption or engaging in energy efficiency.[111] In contrast, demand-metered classes (large commercial and industrial classes) have much less control of their electric bill.[112]

For instance, distribution costs associated with serving a demand-metered customer are collected through a ratcheted facilities demand charge.[113]

> The monthly Facilities Demand will be determined by a comparison of the current month's metered demand and the metered demand recorded in each of the previous 11 months. If there are less than 11 previous months of data, all available data from previous months will be used. The monthly Facilities Demand will be the maximum demand as determined by this comparison or 40 kW, whichever is greater.[114]

This means that demand-metered customers are assessed a facilities demand charge based upon their highest demand for the previous 12 months. So while a customer may close during the pandemic, and not impose any further demand, these customers must still pay the facilities demand charge based upon the highest demand in the previous 12 months.

Similarly, the fixed costs associated with generation and transmission service for a demand-metered customer are largely collected through a demand charge which is based upon the highest 15 minutes of demand in a month.

> The monthly Metered Demand will be determined from the highest fifteen minute integrated kilowatt demand registered during the month by a

[111] See, MECG Responsive Brief, page 14 (citing to Exhibit 26, Lyons Direct, page 53).
[112] *Id.* at pages 14 and 15.
[113] Exhibit 355.
[114] See, for example, Exhibit 355, General Power Service Rate Schedule, *Determination of Monthly Facilities Demand*.

> suitable demand meter. The monthly Billing Demand will be the monthly Metered Demand or 40 kW, whichever is greater.[115]

This means that demand-metered customers are assessed a demand charge based upon their highest 15 minutes of demand in a month. Therefore, a demand-metered customer, if they impose any demand in a month, will be assessed the metered demand charge. Ultimately, the Commission finds that Public Counsel's recommendation that the residential subsidy be increased to account for the pandemic is without merit.

68. In the final analysis, the Commission recognizes that it needs to be cognizant of the significant residential subsidy that exists in Empire's rates. As it has done in each of the previous two Empire rate cases, the Commission will take steps to further address this residential subsidy. With this in mind, and as detailed earlier, the Commission orders a revenue neutral shift to eliminate 25% of the residential subsidy. The beneficiaries of this shift shall be as recommended by MECG.

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[115] See, for example, Exhibit 355, General Power Service Rate Schedule, *Determination of Billing Demand*.

VI. RATE DESIGN FOR DEMAND-METERED CLASSES

Issue 2(e): How should the rates for each customer class be designed?

69. In the non-unanimous stipulation, the Signatories agreed that customer service charges shall remain at current levels.[116] This provision was not objected to by Public Counsel.[117] Therefore, the Commission shall treat this provision as unopposed and finds that it is an appropriate resolution of the customer service charge issue.

70. For many classes (residential, commercial, small heating, feed mill and grain elevator service), customers are only charged a customer charge and energy charges.[118] Given that the customer charge is remaining at current levels, any change in rates for these classes must necessarily be applied to the energy charges.

In contrast, demand-metered customers (General Power; Large Power; Total Electric Building; Special Transmission Service – Praxair (SC-P); and Special Transmission Service (ST)) are charged a customer charge; energy charges; facilities demand charge; and a demand charge).[119] Therefore, while the customer charge will stay at current levels, any rate decrease as ordered previously must be reflected through the demand charge; facilities demand charge and / or energy charges.

71. The evidence indicates that, for the demand-metered classes, Empire collects a significant amount of fixed costs through energy charges. As Empire readily acknowledges, while demand costs [fixed costs] represent 53% of the LP class cost of service, only 32% of the LP class revenue requirement is collected through demand

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[116] *Global Stipulation and Agreement*, filed April 15, 2020, provision 5.
[117] See, *Public Counsel's Objection to Parts of the Global Stipulation and Agreement filed April 15, 2020*, filed April 16, 2020.
[118] Exhibit 355.
[119] *Id.*

charges.[120] Similarly, while energy costs represent only 45% of the LP class' cost of service, Empire collects 68% of its LP revenues through energy charges.[121] Clearly then, a significant portion of the fixed costs for the LP class are inappropriately collected on a usage basis through energy charges.

72. MECG urges the Commission to address this issue by implementing the rate reduction ordered earlier for these classes through a reduction in the class energy charges.[122] Empire agrees. "The Company supports MECG's recommendation to apply approved increase for the LP class to the billing demand and facility charges and ***apply any approved decreases to the energy charge***. This approach better aligns recovery of demand-related costs through demand charges and energy related costs through energy-related charges."[123]

73. In its Responsive Brief, Staff raises concerns with MECG's proposal. Specifically, Staff suggests that MECG's proposal could "potentially decreas[e] the rate paid by some customers for energy below the cost of obtaining that energy from the SPP integrated market."[124] The Commission finds that Staff's concern is misplaced.

74. ***First***, the Commission finds that the evidence indicates that the load weighted and loss adjusted local marginal price for energy in the SPP integrated market is approximately $0.03 / kWh.[125] As reflected in Exhibit 355, the class with the lowest energy charges (SC-P) still has energy charges that are well above this threshold.

[120] Exhibit 26, Lyons Direct, pages 35-36.
[121] Exhibit 28, Lyons CCOS Rebuttal, page 35
[122] MECG Initial Brief, pages 40-43.
[123] Exhibit 28, Lyons CCOS Rebuttal, pages 34-35 (emphasis added).
[124] Staff Initial Brief, page 14.
[125] Exhibit 351, Maini Rebuttal, page 24.

ENERGY CHARGE, per kWh:	Summer Season	Winter Season
On-Peak Period	$ 0.05412	$ 0.03838
Shoulder Period	$ 0.04371	
Off-Peak Period	$ 0.03373	$ 0.03184

The energy charges for the LP and GP rate classes are even further above the market price of energy. Specifically, the energy charges for the GP class are all above 6.4 cents / kWh. Similarly, the energy charges for the LP class are all above 3.6 cents / kWh.[126] Therefore, the Commission could reduce the SC-P rates by 5% and still remain of Staff's suggested threshold. For the GP class, the Commission could cut energy charges by over half and still be above Staff's suggested floor.

75. ***Second***, the evidence indicates that Empire will be immediately filing another rate case to reflect its capital investment in wind generation. Capital investment, as a fixed costs, should be recovered on a per kW basis through either a demand or facilities demand charge. Only variable costs should be recovered on a per kWh basis through energy charges. "The addition of this wind generation [in the next case] will have the effect of increasing fixed costs and reducing variable costs. As a result, the demand charges should increase in that case."[127] Given that demand charges will likely increase in the next case to account for these increased fixed costs, the Commission finds that it would be illogical to reduce demand charges here, as Staff seems to suggest, only to then increase them in the next case.[128]

[126] Exhibit 355.
[127] *Id.*
[128] *Id.* at pages 24-25.

76. ***Third***, the Commission recognizes that MECG's proposal is not novel. In the last Ameren and KCPL / GMO rate cases, the Commission took steps in both cases to reduce the industrial class energy charges.[129]

Given all of these reasons, the Commission finds that MECG's rate design proposal for the demand-metered classes is appropriate.

[129] For instance, in the recent Ameren case, the rate reduction for the industrial classes was implemented by reducing the energy charges. See, *Order Approving Stipulation and Agreements*, Case No. ER-2019-0335, issued March 18, 2020, Attachment Corrected Non-Unanimous Stipulation and Agreement Exhibit J. For KCPL and GMO, the recent rate reduction for the industrial classes was also implemented by reducing the industrial class energy charges. See, *Order Approving Stipulations and Agreement*, Case Nos. ER-2018-0145 / 0146, issued October 31, 2018, Attachment Stipulation 4, page 4 ("The LPS and LGS rate design will be an equal percentage decrease applied only to the energy blocks.").

VII. NON-OPPOSED RATE DESIGN STIPULATIONS

77. The April 14, 2020 non-unanimous stipulation included several issues pertaining to rate design and consolidation of rates. In its April 15, 2020 pleading, Public Counsel indicated that it did not oppose many of these provisions. As such, the Commission will treat these provisions as unopposed and approve them as follows:

78. **Should the GP and TEB rate schedules be fully consolidated?** In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will submit a rate analysis for the alignment of GP / TEB rates in its next rate case."[130] The Commission will approve this provision.

79. **Should the CB and SH rate schedules be partially consolidated?** In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will submit a rate analysis for the alignment of CB / SH rates in its next rate case."[131] The Commission will approve this provision.

80. **Should "grandfathered" multifamily customers taking service through a single meter be given the option of being served on the CB/SH rate schedule?** In the non-unanimous stipulation, the Signatories agreed that "[w]hen the Company files its next rate case, the Company will include testimony regarding whether or not it proposes to change its tariffs to allow mastermetered apartments to be served under CB / SH."[132] The Commission will approve this provision.

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[130] Non-Unanimous Stipulation, provision 14.
[131] Non-Unanimous Stipulation, provision 15.
[132] Non-Unanimous Stipulation, provision 18.

81. **What should be the amount of the residential customer charge?**

In the non-unanimous stipulation, the Signatories agreed that “There will be no changes to the customer charges in this proceeding.”[133] The Commission will approve this provision.

82. S**hould Empire continue its Low-Income Pilot Program as is, or modify it?**

In the non-unanimous stipulation, the Signatories agreed that “[t]he Company’s Low-Income Pilot Program will remain in place with no changes made in this case, and the Company will track all costs until the next rate case.” Furthermore, the Signatories agreed that “[t]he Company, Staff, and OPC agree to meet at least twice prior to the filing of Empire’s next rate case to discuss the Company’s Low Income Pilot Program and whether or not modifications are warranted.”[134] This provision was not opposed by Public Counsel. The Commission will approve this provision.

83. **Should Empire be ordered to consolidate the PFM rate schedules into the GP/TEB rate schedule in a future proceeding?**

In the non-unanimous stipulation, the Signatories agreed that “[t]he Company will propose the elimination of the Feed & Grain [PFM] rate in its next general rate case.”[135] This provision was not opposed by Public Counsel. The Commission will approve this provision.

[133] Non-Unanimous Stipulation, provision 5.
[134] Non-Unanimous Stipulation, provisions 21 and 22.
[135] Non-Unanimous Stipulation, provision 16.

84. **Should Empire be ordered to incorporate shoulder months into the Special Contract / Praxair rate structures in the next rate proceeding?**

In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will work with parties to explore modification of the rate structures of all rate schedules to subdivide the current "Winter" billing season into a "Peak Winter" and two "Shoulder Month" seasons, to reflect at a minimum the difference in the cost of market energy among current "Winter" months to the extent it is consistent with reasonable rate design principles."[136] This provision was not opposed by Public Counsel. The Commission will approve this provision.

85. **Should Empire be ordered to work to incorporate shoulder months into the rate structures of all non-lighting rate schedules?**

In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will work with parties to explore modification of the rate structures of all rate schedules to subdivide the current "Winter" billing season into a "Peak Winter" and two "Shoulder Month" seasons, to reflect at a minimum the difference in the cost of market energy among current "Winter" months to the extent it is consistent with reasonable rate design principles."[137] This provision was not opposed by Public Counsel. The Commission will approve this provision.

86. **Should Empire be ordered to retain each of the following: Primary costs by voltage; Secondary costs by voltage; Primary service drops; Line extension by rate schedule and voltage; Meter costs by voltage and rate schedule?**

In the non-unanimous stipulation, the Signatories agreed that "[p]rior to the next rate

[136] Non-Unanimous Stipulation, provision 17.
[137] Non-Unanimous Stipulation, provision 17.

case, the Company will identify and provide the data required to determine: primary distribution costs by voltage; secondary distribution costs by voltage; primary voltage service drops; line extension by rate schedule and voltage; and, meter costs by voltage and rate schedule. If the required data is not readily available, the Company will identify and implement the actions necessary to obtain it as quickly as possible."[138] This provision was not opposed by Public Counsel. The Commission will approve this provision.

87. **Should Empire be ordered to use of AMIs for near 100% sample load research as soon as is practical, but no more than 12 months after 90% of AMI are installed?**

In the non-unanimous stipulation, the Signatories reached multiple agreements with regard to the deployment of AMI and the use of the data resulting from such deployment.[139] This provision was not opposed by Public Counsel. The Commission will approve this provision.

88. **Should Empire be ordered to retain individual hourly data for future bill comparisons?**

In the non-unanimous stipulation, the Signatories agreed that Empire will "[r]etain individual hourly data for use in providing bill comparison tools for customers to compare rate alternatives"[140] This provision was not opposed by Public Counsel. The Commission will approve this provision.

[138] Non-Unanimous Stipulation, provision 12.
[139] Non-Unanimous Stipulation, provision 13a.
[140] Non-Unanimous Stipulation, provision 13b.

89. **Should Empire be ordered to retain coincident peak determinants for use in future rate proceedings?**

In the non-unanimous stipulation, the Signatories agreed that Empire will "[r]etain coincident peak determinants for use in future rate proceedings."[141] This provision was not opposed by Public Counsel. The Commission will approve this provision.

90. **How should any residential revenue requirement increase or decrease be apportioned to the energy (kWh) rates?**

The residential schedule only provides for a customer and energy charges.[142] In the non-unanimous stipulation, the Signatories agreed that "[t]here will be no changes to the customer charges in this proceeding."[143] This provision was not opposed by Public Counsel. Given that the residential customer charge will not change, any change in the residential revenue requirement must be apportioned to the energy (kWh) rates. The Commission will approve this provision.

91. **How should any CB and SH revenue requirement increase or decreasebe apportioned to the energy (kWh) rates?**

The CB and SH rates schedules only provides for a customer and energy charges.[144] In the non-unanimous stipulation, the Signatories agreed that "[t]here will be no changes to the customer charges in this proceeding."[145] This provision was not opposed by Public Counsel. Given that the CB and SH customer charges will not change, any change in the CB and SH revenue requirement must be apportioned to the energy (kWh) rates. The Commission will approve this provision.

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[141] Non-Unanimous Stipulation, provision 13c.
[142] See, Exhibit 355.
[143] Non-Unanimous Stipulation, provision 5.
[144] See, Exhibit 355.
[145] Non-Unanimous Stipulation, provision 5.

VIII. WNR / SRLE ADJUSTMENT MECHANISMS

Issue 4(a): Should the Commission approve, reject or approve with modifications Empire's proposed Weather Normalization Rider?

Issue 4(b): Is it lawful for the Commission to authorize Empire to implement a Sales Reconciliation to Levelized Expectations ("SRLE") mechanism, such as those Staff and Empire are proposing in this case?

Issue 4(c): Should the Commission adopt Staff's Sales Reconciliation to Levelized Expectations Proposal ("SRLE") or approve the SRLE with modifications as suggested by the Company?

92. In 2018, the General Assembly enacted SB564. One portion of that legislation, Section 386.266.3 allows electric utilities to apply for an adjustment mechanism that adjusts rates to account for changes in utility revenues associated with weather, conservation or both.

> Subject to the requirements of this section, any gas or electrical corporation may make an application to the commission to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both.

93. As further provided in the statute, "eligible customer classes" means the residential class and classes that are not demand metered. In its brief, MECG explains the rationale underlying the limitation of "eligible customer classes" to classes that are not demand metered. Non-demand metered classes that rely largely on energy charges for the collection of fixed costs. As Empire witness Lyons points out, 90.9% of the residential revenue requirement is collected through energy charges.[146] For Empire, the

[146] Exhibit 26, Lyons Direct, page 53. Similarly, 89.0% of the Commercial and 92.0% of the Small Heating revenue requirements are collected through energy charges. *Id.*

non-demand metered classes are the residential (RG); commercial (CB); small heating (SH) and feed mill / grain elevator service (PFM).[147]

94. In contrast, demand metered classes rely on demand charges for the collection of fixed costs. For Empire, this includes both a demand charge (used to collect generation and transmission costs) as well as a ratcheted facilities demand charge (used to collect distribution costs).[148] For these classes then, fixed costs are ideally collected through the demand charges and variable costs are collected through the energy charge. The demand-metered classes for Empire are general power (GP); large power (LP); total electric building (TEB); special transmission service – Praxair (SC-P); and special transmission service (ST).[149]

95. The heavy reliance on energy charges for the collection of fixed costs in the non-demand metered classes means that Empire is heavily susceptible to variations in weather and conservation for the collection of its fixed costs.

> [I]ncreases or decreases in consumption will likely cause utilities to over- or under-collect their cost of service. Warmer than normal weather during the winter, for example, will likely result in sales that are below historical test year sales, reducing the likelihood that utilities recover their Commission-authorized cost of service. Conversely, colder than normal weather during the winter will likely result in sales that are above historical test year sales, increasing the likelihood that utilities recover more than their Commission-approved cost of service.[150]

96. In the non-unanimous stipulation, the Signatories seek to break the link between Empire's recovery of fixed costs for the non-demand metered classes and those classes consumption of electricity. Given this, the Signatories recommended the approval, under Section 386.266.3, of a mechanism closely aligned with the mechanism

[147] Exhibit 355.
[148] Exhibit 355.
[149] Exhibit 355.
[150] Exhibit 26, Lyons Direct, page 54.

initially set forth by Staff and denominated Sales Reconciliation to Levelized Expectations ("SRLE").

97. On April 16, 2020, Public Counsel objected to portions of the non-unanimous stipulation including the recommended SRLE. As such, the Commission may not simply approve that mechanism, but must instead make specific findings of fact supporting its approval.

98. The recommended SRLE is structured in a similar fashion to that recommended by Staff. In an effort to comply with the statutory requirement that the mechanism account for changes in usage associated with weather and conservation, Staff's recommended SRLE mechanism attempts to isolate that portion of residential usage that is static from that portion that is susceptible to changes caused by weather and conservation.[151] For the residential class:

> Staff has reviewed Empire's cumulative frequency distribution data to determine the maximum level of usage per customer per month that is more or less constant all year. Usage of approximately 400 kWh per customer per month appears unlikely to be impacted by weather or conservation in the immediate future.[152]

99. Staff conducted a similar analysis for the small commercial and small heating classes which showed that usage above 700 kWh was subject to variation caused by weather and conservation.[153]

100. The SRLE recommended in the non-unanimous stipulation is consistent with Staff's analysis. That is, the recommended mechanism utilizes both the 400 kWh threshold for the residential SRLE and a 700 kWh threshold for both the commercial and

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[151] Exhibit 104, Staff Class Cost of Service Report, pages 3-13.
[152] *Id.* at page 4.
[153] Exhibit 104, Staff Class Cost of Service Report, pages 6-8.

small heating SRLE.[154] Given this, the Commission finds that the recommended SRLE is in compliance with the statutory requirement that it only consider usage variations resulting from weather, conservation or both.

101. In addition to arguing that the recommended SRLE does not comply with Section 386.266.3, Public Counsel also argues that the Commission should not approve this mechanism because of Empire's short-term increase in estimated bills. The Commission finds that the increase in estimated bills is not justification for denial of the recommended mechanism. As Empire witness Lyons points out, while a customer's bill may be impacted through the estimation process, class cost of service studies and the proposed SRLE mechanism rely on aggregate bill data.

> [T]he Company believes that the data quality issues do not result in a material impact on the results of the CCOS nor render them unreliable. The CCOS relies on aggregate customer data rather than individual customer data, and any concerns with individual customer data do not appear to impact the results of the CCOS.[155]

102. Next, Public Counsel argues that the Commission is prohibited from authorizing the requested mechanism under Section 386.266.13 because it has not promulgated rules specific to the requested mechanism. As Staff points out, however, the requested mechanism may only be requested in the context of a general rate proceeding.[156] In this regard, the Commission has approved rules relative to the filing requirements for a general rate proceeding.[157] As such, the Commission has complied with the requirement of Section 386.266.13.

[154] Global Settlement, Appendix C, page 3.
[155] Exhibit 28, Lyons Surrebuttal, page 10.
[156] Section 386.266.5.
[157] 20 CSR 4240-3.030

103. Finally, Public Counsel argues that usage during the Covid-19 pandemic is unreliable. Such a rationale is not a legal impediment to the Commission authorizing the requested mechanism. The record shows that Empire has not been earning its authorized return from the residential class. In fact, Empire is earning less from the residential class than it did in 2014 when the Commission took steps to eliminate the residential subsidy.[158] The implementation of the requested mechanism will assist Empire in earning its authorized return from the non-demand metered classes.

104. The Commission finds that the requested mechanism appropriately accounts for usage variations caused by weather and / or conservation. Furthermore, the Commission finds that the requested mechanism "is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity."[159] Given this, the Commission approves the SRLE mechanism set forth in the non-unanimous stipulation.

[158] Exhibit 29, Lyons Surrebuttal, page 11.
[159] Section 386.266.5(1).

IX. TAX CUTS AND JOBS ACT IMPACT

Issue 12(a): How should the Commission treat the 2017 TCJA regulatory liability the Commission established in Case No. ER-2018-0366 when setting rates for Empire in this case?

105. Section 393.137, implemented in 2018, provides two things. First, the statute authorizes the Commission to adjust a utility's rates to prospectively account for the 2017 change in the federal corporate tax rate. Second, relevant to the issue in this case, the statute requires the Commission to defer, as a regulatory liability, the financial impact of the tax reduction for the period from January 1, 2018 through the date on which rates were prospectively changed (the "stub period benefits"). The statute then mandates that the Commission include these stub period benefits in rates in the utility's subsequent general rate proceeding.

> The commission shall also require electrical corporations to which this section applies, as provided for under subsection 1 of this section to defer to a regulatory asset the financial impact of such federal act on the electrical corporation for the period of January 1, 2018, through the date the electrical corporation's rate are adjusted on a one-time basis as provided for in the immediately preceding sentence. The amounts deferred under this subsection shall be included in the revenue requirement used to set the electrical corporation's rates in its subsequent general rate proceeding through an amortization over a period determined by the commission.[160]

106. In Case No. ER-2018-0366, the Commission held that Empire fell within the scope of Section 393.137.[161] Given this, the Commission prospectively changed Empire's rates to account for the reduction in the federal corporate tax rate.[162] In

[160] Section 393.137.3

[161] *Report and Order*, Case No. ER-2018-0366, issued August 15, 2018, at pages 12-13 ("After considering the facts and the applicable law, the Commission finds that Empire did not have a "general rate proceeding" within the meaning of section 393.137 pending before the Commission on June 1, 2018. For that reason, section 393.137 does apply to Empire.").

[162] *Id.* at page 14 ("Empire's rates should be adjusted prospectively to reflect a reduction in its annual base rate revenue requirement of $17,837,022. That reduction shall take effect on August 30, 2018, as allowed by the authority granted to the Commission in section 393.137.3.").

addition, consistent with the statute, the Commission ordered Empire to create a regulatory liability for the stub period tax benefits. "Having found that section 393.137.3 applies to Empire, the Commission must comply with that statute by ordering Empire to establish a regulatory liability to account for its excess earnings during the period of January 1 through August 30, 2018."[163]

107. Given that this is the "subsequent general rate proceeding", the Commission is required to amortize these stub period tax benefits into rates. In the non-unanimous stipulation, the Signatories included the following provision:

> An amortization of the balance of the stub period amortization of $11,728,453, in the amount of $5,000 monthly, is included in the revenue requirement for this case. The amortization balance, and the appropriate amortization period, will be reevaluated in the next general rate case.[164]

108. On April 16, 2020, Public Counsel objected to this provision of the non-unanimous stipulation. As such, the Commission may not simply approve that mechanism, but must instead make specific findings of fact supporting its approval.

109. The Commission finds that the Tax Cuts and Jobs Act provision in the non-unanimous stipulation complies with Section 393.137. Specifically, the Signatories have included an amortization of the stub period benefits as required by the statute. In an effort to limit the rate change in this and Empire's subsequent case, the Signatories included the necessary amortization while preserving the majority of these benefits until Empire's next rate case when a significant investment in wind will be included in rates. Therefore, the Commission approves the Tax Cuts and Jobs Act provision in the non-unanimous stipulation.

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[163] *Report and Order*, Case No. ER-2018-0366, issued August 15, 2018, at page 22.
[164] *Global Stipulation and Agreement*, page 2, provision 3(b).

Respectfully submitted,

/s/ David L. Woodsmall

David L. Woodsmall, MBE #40747
308 E. High Street, Suite 204
Jefferson City, Missouri 65101
(573) 797-0005
david.woodsmall@woodsmalllaw.com

ATTORNEY FOR THE MIDWEST ENERGY CONSUMERS GROUP

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing pleading by email, facsimile or First Class United States Mail to all parties by their attorneys of record as provided by the Secretary of the Commission.

David L. Woodsmall

Dated: May 18, 2020