Exhibit No.:	
Issue:	Fuel Adjustment Clause; Transmission Costs; Property Taxes;;; MEEIA; FAC; Electric Vehicle Charging; Rate Case Expenses; Greenwood Solar Facility and AMI Opt-Out
Witness:	Tim M. Rush
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2016-0285
Date Testimony Prepared:	December 30, 2016

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2016-0285

REBUTTAL TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
December 2016

REBUTTAL TESTIMONY

OF

TIM M. RUSH

Case No. ER-2016-0285

Q: Please state your name and business address.

A: My name is Tim M. Rush. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or the "Company") as Director, Regulatory Affairs.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L.

Q: Are you the same Tim M. Rush who filed Direct Testimony in this proceeding?

A: Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond to certain issues presented by parties to this proceeding. Those issues include:

I.) Property tax and transmission expense trackers as presented in the testimony of Midwest Energy Consumer's Group ("MECG") witness Michael Brosch and Missouri Industrial Energy Consumers ("MIEC") witness James Dauphinais;

II.) MEEIA ISSUES

a. The inclusion of MEEIA labor in base rates rather than in the actual MEEIA program costs and recovered in the DSIM rate as presented in the testimony of Staff Dana Eaves;

b. The treatment of the lost sales associated with the implementation of MEEIA programs in the annualization of Staff unit sales and sales revenues;

III.) The modifications to the fuel adjustment clause ("FAC") as presented in the testimony of Office of Public Counsel ("OPC") witnesses Lena Mantle and John Riley, Staff witnesses David Roos and Alan Bax, and MIEC witness James Dauphinais;

IV.) Staff's allocation of the KCP&L Greater Missouri Operations Company's ("GMO") Greenwood solar facility to KCP&L;

V.) Clean Charge Network ("CCN")

a. The rate base treatment of the electrical vehicle charging station investment as presented in the staff report and supported by Byron Murray and OPC witness Geoffrey Marke;

b. The electrical vehicle tariff as presented in the staff report and supported by Byron Murray;

VI.) Recovery of rate case expense; and

VII.) Advanced Meter Infrastructure ("AMI") –Staff's Opt-out recommendation.

I. PROPERTY TAXES AND TRANSMISSION EXPENSES

Q: MECG witness Michael Brosch testifies to his opposition to the Company's proposed use of forecasted property taxes and transmission expenses. How do you respond?

A: I will address property tax and transmission expense trackers separately in the following portion of my testimony.

<u>**PROPERTY TAX TRACKER**</u>

Q: What are the specific reasons for MECG witness Brosch's opposition to the Company's proposed property tax tracker?

A: Consistent with his arguments in our previous KCP&L rate case, Mr. Brosch argues that the Commission should reject the tracker for property taxes because they are 1) not unusual or infrequent, and 2) of insufficient magnitude and volatility. Mr. Brosch believes that the Company has some management control over property taxes. As with his general statements regarding trackers, Mr. Brosch questions whether the Company would diligently manage property taxes if tracker treatment is adopted.

Q: How do you respond to his points?

A: I disagree that an expense must be unusual or infrequent to merit tracker treatment. I would argue that property taxes are a large portion of the overall revenue requirement of the Company, accounting for $50 million annually in expense. I would also say that while Mr. Brosch might believe that the Company has some control of the amount of property taxes paid, that control is minimal at best.

Q: What evidence does Mr. Brosch point to in support of his assertion that property taxes are not of sufficient magnitude to warrant tracker treatment?

A: On p. 38 of his direct testimony, Mr. Brosch asserts that because property taxes amount to about 5.3 percent of overall electric revenues and 6.7 percent of overall expenses they do not have a material impact on financial performance between rate cases. Mr. Brosch misses the point because he does not look at how the mismatch between property taxes included in cost of service (i.e., revenues) and property taxes actually paid (i.e., costs) affected the Company's earnings. The table below is a comparison of the property taxes over the period 2011 through 2018. In 2011, property taxes were established for KCP&L Missouri jurisdiction at $40 million. Two additional cases followed in which the property taxes for KCP&L Missouri jurisdiction were established. Comparing annualized levels of actual property taxes to those included in rates for the annual period shows that for the period 2012 through 2015, the Company under-recovered nearly $16 million, or approximately $4 million per year. This represents an average under-recovery of 9% of property taxes.

Property Tax Expense, Account 408120
Incl Unit Trains charged to Fuel Inv

Calendar Year		Property Taxes (Total Company)	MO Alloc (Per Order)	Property Taxes (MO Juris)	Estimated Property Taxes Recovered	
2011	Actual	72,286,058	54.2243%	39,196,609	089 Case blackbox	ER-2010-355, Eff 5/4/2011
2012	Actual	76,446,625	54.2243%	41,452,647	40,120,435	
2013	Actual	81,533,338	53.4300%	43,563,262	40,943,545	ER-2012-174, Eff 1/26/13
2014	Actual	86,870,907	53.4300%	46,415,126	41,018,373	
2015	Actual	90,715,370	54.2190%	49,184,966	42,821,546	ER-2014-0370, Eff 9/15/15
				180,616,002	164,903,899	
Estimated Property Taxes Unrecovered 2012-2015					15,712,103	
2016	Budget	93,288,092	54.2190%	50,579,871		
2017	Budget	103,944,196	54.2190%	56,357,504		
2018	Budget	109,035,737	54.2190%	59,118,086		

Q: Are there any other conclusions that can be drawn from this table?

A: Yes. As can be seen from the 2016 through 2018 period, the Company expects property taxes to continue to rise and if the Commission uses the same methodology in determining the appropriate property tax levels for this rate case as before, the Company will continue to experience the significant under-recovery of property taxes. The use of forecasted property taxes would alleviate the lag that has been occurring with property taxes.

Q: Has the Commission granted deferral accounting treatment for property taxes in previous cases?

A: Yes. My understanding is that each of the cases mentioned above in which the Commission granted an AAO for gas safety replacement-related costs authorized the deferral, among other things, of property taxes in connection with the replaced facilities. Additionally, in at least one case the Commission granted an AAO to Missouri Gas Energy ("MGE") which authorized MGE to defer property taxes on gas held in storage in the State of Kansas.[1]

Q: Absent a tracker mechanism, can the Company eliminate the negative earnings impact of rising property taxes simply by filing another rate case immediately after the conclusion of this rate case?

A: No. As I demonstrated in the table above, without a tracker, any earnings shortfall resulting from a mismatch between actual property taxes and the rate allowance for those

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[1] *Report and Order*, Re: Missouri Gas Energy, Case NO. GR-2006-0422.

costs included in rates will be lost forever. Although rates can be adjusted on a going forward basis to reflect the increased property taxes experienced during the historical test year for the second rate case, those increased cost levels will only be recovered on a going forward basis, and if property tax costs continue to rise as expected, the Company will experience more earnings shortfall due to under-recovery of property taxes that can never be recovered.

TRANSMISSION EXPENSES USING FORECASTED COSTS

Q: What are the specific issues that MECG witness Michael Brosch has with the Company's proposed use of forecasted transmission expenses as a tracker?

A: Mr. Brosch essentially makes the same arguments against using forecasted costs for the transmission tracker as he does for the property tax tracker recommendation proposed by the Company in this case.

Q: Do you agree with his arguments against the including forecasted tracker mechanism?

A: No. As the Company has seen case after case, the Company is not recovering its transmission costs, due to the rising costs the Company is experiencing. This issue has been addressed several times before and the outcome has been the same, which is to not allow forecasted transmission costs, or transmission costs in the FAC, in rates. While this has been the outcome in prior cases, I believe that the recent report[2] sponsored by the Staff of the Commission should help to give some light to the fact that utilities are facing rising costs and that the Commission has the "tools" to help address this issue. Including

[2] *Staff Report*, dated October 17, 2016, MPSC Docket No. EW-2016-0313.

forecasted transmission expenses in rates is a way to address the lag issue that utilities face.

Q: What evidence does Mr. Brosch point to in support of his assertion that transmission expense are not of sufficient magnitude to warrant tracker treatment?

A: On pp. 30 of his direct testimony, Mr. Brosch asserts that because transmission expenses amount to about 4.0 percent of overall electric revenues and 5.1 percent of overall expenses they do not have a material impact on financial performance between rate cases. This evidence misses the point by ignoring the impact forecasted transmission expense increases will have on the Company's earnings. Similarly, as I demonstrated above with the discussion of property taxes, the table below is a comparison of transmission expenses over the period 2011 through 2018. In 2011, transmission expenses were established for KCP&L Missouri jurisdiction at $8.8 million. Two additional cases followed in which transmission expenses for KCP&L Missouri jurisdiction were established. Comparing annualized levels of actual transmission expenses to those included in rates for the annual period shows that for the period 2012 through 2015, the Company under-recovered nearly $44 million, or approximately $11 million per year. This represents an average under-recovery of over 45% of transmission expenses.

Transmission Expense, Account 456.1, 561.4, 561.8, 565, 575.7 and 928003

Calendar Year		Transmission (Total Company)	MO Alloc (Per Order)	Transmission (MO Juris)	Estimated Transmission Recovered	
2011	Actual	16,407,895	53.5000%	8,778,224	089 Case blackbox	ER-2010-355, Eff 5/4/2011
2012	Actual	24,288,290	53.5000%	12,994,235	6,720,419	
2013	Actual	40,700,298	52.7000%	21,449,057	13,421,391	ER-2012-174, Eff 1/26/13
2014	Actual	51,486,235	52.7000%	27,133,246	14,030,570	
2015	Actual	59,850,952	57.2300%	34,252,700	17,617,614	ER-2014-0370, Eff 9/15/15
				95,829,238	51,789,994	
Estimated Transmission Expenses Unrecovered 2012-2015					44,039,244	
2016	Budget	62,137,619	57.2300%	35,561,359		
2017	Budget	71,812,002	57.2300%	41,098,009		
2018	Budget	72,488,267	57.2300%	41,485,035		

Q: Absent a tracker mechanism, can the Company eliminate the negative earnings impact of rising transmission expenses simply by filing another rate case immediately after the conclusion of this rate case?

A: No. As I demonstrated in the table above, without a tracker, any earnings shortfall resulting from a mismatch between actual transmission expenses and the rate allowance for those costs included in rates will be lost forever. Although rates can be adjusted on a going forward basis to reflect the increased transmission expenses experienced during the historical test year for the second rate case, those increased cost levels will only be recovered on a going forward basis, and if transmission costs continue to rise as expected, the Company will experience more earnings shortfall due to under-recovery of transmission expenses that can never be recovered. The Staff of the Commission in a recent report to the Commission on alternatives rate recognizes that things can be done to address regulatory lag that utilities are currently experiencing.

Q: MIEC witness James R. Dauphinais opposes the inclusion of a significant portion of the transmission costs in the FAC and also opposes the projected level, whether in the FAC or base rates. How do you respond?

A: Mr. Dauphinais indicates the reason he opposes the use of forecasted level of transmission costs in base rates is that he fears the Company may over-recover its total costs. He opposes the inclusion of all transmission costs in the FAC is that he proposes to follow the existing FAC methodology at KCP&L.

Q: How do you respond to Mr. Dauphinais' position that he is concerned that the Company may over-recover its total costs?

A: His concern is unfounded. The Company has not earned its authorized return on investment in any time in recent history. The escalation in costs is a "known" fact, even recognized by Mr. Dauphinais.

Q: Please explain what KCP&L's proposal is for the treatment of transmission costs if the Commission does not include all transmission costs in the FAC.

A: The proposal of the Company is to use an asymmetrical tracker for those costs not reflected in the FAC whereby the Company would refund to customers any over-recovery of transmission costs and if actual costs were greater than the projected amount, KCP&L would not recover the difference.

Q: Would such a mechanism protect customers from any over-recovery of those transmission costs?

A: Yes.

II. MEEIA ISSUES

MEEIA LABOR IN THE RATE CASE VERSUS THE DSIM

Q: Please explain what is being proposed by Staff witness Dana Eaves in this case?

A: Staff is proposing to include the internal labor costs for MEEIA programs in the base rates for KCP&L Missouri operations. Currently, those costs are charged directly to the MEEIA program costs and are reflected in the DSIM Charge rider associated with MEEIA. The DSIM rate is adjusted twice a year and includes labor and expenses on a projected basis for the MEEIA programs.

Q: Are the internal labor costs treated differently for the DSIM rate as compared to how the staff is recommending treatment of the costs if they were included in the base rates of KCP&L.

A: Yes. Currently in the DSIM rate, the labor costs, along with other program costs are projected for a six month period and included in the DSIM rate. These costs are then reconciled to actual expenses with each successive DSIM rate filing. As such, internal labor for the MEEIA programs is recovered in a real time basis. This is in comparison to the approach taken by Staff in a rate case where they propose to us a historical base level of employees, essentially set at the time of the true-up in the case. GMO uses the same methodology as KCP&L in the establishment of the DSIM for its MEEIA programs where internal labor is treated on a projected basis and true-up for each six month change to the DSIM rate.

Q: Are the same people working on KCP&L MEEIA programs also working on GMO MEEIA programs?

A: Yes. The same people who are working on KCP&L MEEIA programs also work on GMO programs. There internal labor costs are assigned to each utility program based on what activities they are doing. These costs are accounted for and provided to parties as part of the costs of providing the MEEIA programs. Their labor is actually charged to each MEEIA program so as to be able to manage the program costs and benefits used in managing the overall programs. These overall costs are used in both the establishment of programs initially, as well as the evaluation, measurement and verification that go on to ensure successful programs. Managing internal labor of the MEEIA program and DSIM rate is important in the overall program. Placing some level of employment in base rates to represent the overall organization does not achieve the intended purpose of the MEEIA rules.

Q: Since the internal labor is projected and included in the DSIM rate today, would it be difficult to follow Staff's recommendation.

A: Yes. This would be difficult to implement. Somehow, the Company would need to unwind the internal payroll costs that is currently being recovered in the DSIM rate in such a way to be reconciled with actuals and not over- or under the internal labor costs that Staff is suggesting be included in this rate case in base rates for the KCP&L Missouri operations. We would then need to be able to track those internal labor costs being charged to the GMO operations DSIM from those that would be reflected in base rates for KCP&L. All of this would be difficult to administer from an allocations perspective. But more importantly, it would deviate from what the intended purpose of the DSIM rate is designed to reflect. The DSIM rate is designed to reflect the cost of the energy efficiency programs, as well as to provide timely recovery of these costs. Therefore, we oppose the inclusion of the MEEIA labor in the rate case and its cost of service.

MEEIA ADJUSTMENT IN THE ANNUALIZED REVENUES

Q: What are the issues that you are addressing with Energy Efficiency and annualized revenues in the case?

A: The Company made an adjustment in its direct filing in this case to reflect the energy efficiency (e.g. MEEIA Cycle 1 and 2 programs) impact on normalized and annualized sales. The Staff has not made a similar adjustment in this case to reflect the impact of the MEEIA programs in its direct filing. Therefore, my testimony will address the need for this adjustment and address the Staff's failure to include in the Staff's revenue requirement the appropriate energy efficiency adjustments of test year monthly kWh sales and peak loads found in Schedule ARB-2.

Q: What is the basis for the Company's energy efficiency adjustments of test year monthly kWh sales and peak loads?

A: As referenced in the direct testimony of Company witness Albert R. Bass, Jr., the Company's energy efficiency adjustments of test year monthly kWh sales and peak loads was included based on a number of factors, including the Non-Unanimous Stipulation And Agreement Resolving MEEIA Filings (filed on November 23, 2015) approved by the Commission in Case No. EO-2015-0240 ("MEEIA 2 Stipulation"). Those factors include the knowledge of the actual known and measurable loss in sales specifically identifiable from energy efficiency programs that are in place. The MEEIA 2 Stipulation provides that "Upon filing a rate case, the cumulative, annualized, normalized kWh and kW savings will be included in the unit sales and sales revenues used in setting rates as of an appropriate time (most likely two months prior to the true-up date) where actual results are known prior to the true-up period, to reflect energy and demand savings in the billing determinants and sales revenues used in setting the revenue requirements and tariffed rates in the case." (MEEIA 2 Stipulation, p. 13)(Schedule TMR-6)

Q: What energy and demand savings are to be included in the adjustments?

A: The MEEIA 2 Stipulation provides that "annual kWh energy savings from the first month of the test period through the month ending where actual results are available (most likely two months prior to the true-up date) by customer class from all active MEEIA programs, excluding Home Energy Reports and Income-Eligible Home Energy Reports will be included in the adjustment." (MEEIA 2 Stipulation, p. 14)(Schedule TMR-6)

Q: What MEEIA programs were active in the period from the first month of the test period through the month ending where actual results are available?

A: KCP&L had 10 active MEEIA Cycle 1 programs which generated energy and demand savings for customers throughout the test period ending December 31, 2015. In addition, pursuant to the MEEIA 2 Stipulation the Company was authorized to extend C&I Custom Rebate program for projects that were approved under Cycle 1 through June 30, 2016. This program generated significant additional customer energy and demand savings during the period between January 1, 2016 and June 30, 2016. Lastly, the Company's MEEIA Cycle 2 programs were approved effective April 1, 2016 and generated energy and demand savings for customers through December 31, 2016.

Q: Has the customer energy and demand savings from these programs resulted in a permanent reduction in sales and demand and ultimately revenues?

A: Yes. Just like the adjustments that are reflected for weather, customer and known and measurable specific customer adjustments that are made in the annualized unit sales and sales revenues used in setting rates, the energy and demand savings from energy efficiency must also be made to the annualized unit sales and sales revenue in this case.

Q: Why is the energy efficiency annualization adjustment to test period kWh sales needed?

A: The purpose of a test period and true-up period is to set a basis for determination of rates which is close to the dates rates would go into effect in a rate case. Adjustments to the test period and true-up period are made to reflect known and measurable changes that help develop rates which will be representative of conditions prevailing when they go into effect sometime after the true-up period. When addressing the unit sales and demand levels, adjustments are made to reflect normal weather, customer annualizations (e.g. establish customer levels at a time closer to when rates go into effect) and adjustments for known and measurable changes from the test period, such as customer usage changes not reflected in the weather normalization process. One of the outcomes of the last rate case, was additional revenues added to the case to reflect rate shifting that would occur as a result of savings from customers moving from one rate class to another based on the outcome of the rate design in the case. This adjustment must also be reflected in the annualization process. This is discussed in the testimony of Company witness Bass. This can include anything from specific customers whose usage has specifically increased or decreased from the test period to where a new customer was added and the respective changes in load, to an adjustment for energy efficiency. This is where the adjustment for energy efficiency should be addressed as set out in the Stipulation and Agreement for Cycle 2 MEEIA. Test period kWh sales only reflect a partial year effect of energy savings installed during the test period and does not reflect any effect of energy savings after the test period through the true-up period. For example, an energy efficiency measure installed July 1, 2015, would have reduced billed kWh sales in July through December 2015, but January through June 2015 kWh sales would not reflect the effect of reduced energy resulting from the installation of this measure. This adjustment is to reflect the full year effect of energy efficiency savings occurring through the true-up date.

Q: Why do you believe that test period kWh sales adjustments to reflect MEEIA Cycle 1 energy and demand savings need to be included?

A: The language used in the MEEIA 2 Stipulation, "all active MEEIA programs", was purposefully broad to include MEEIA Cycle 1 and Cycle 2 programs. Nowhere in the stipulation did it exclude Cycle 1 or specify Cycle 2 as the only programs to be reflected in the adjustment. The Stipulation specified all MEEIA programs, excluding Home Energy Reports and Income-Eligible Home Energy Reports, to be included in the computation for this rate case adjustment. The Stipulation addresses both Cycle 1 and Cycle 2 in numerous places throughout the agreement. Additionally, if these savings are not reflected, the kWh sales upon which current rates are to be set will be significantly over-stated causing the Company to be further hindered from earning its authorized return.

Q: Will the inclusion of MEEIA Cycle 1 energy and demand savings result in "double dipping" between the MEEIA Cycle 1 TD-NSB recovery through the MEEIA Demand Side Investment Mechanism (DSIM) and the base rates established in this case?

A: No.

Q: Why?

A: Because the reduction in sales has already occurred and the reflection of the energy efficiency reduction in unit sales and sales revenues is for rates going forward only. It is no different than making an adjustment because a customer left the system or a customer came onto the system (as in the customer annualization) or making a weather adjustment to reflect normal weather). The point is to try an develop overall customer usage reflective of the overall test period adjusted to the true-up for unit sales and sales revenues to be consistent with the plant and expenses in the case.

I prepared a pro forma analysis of the Company's TD-NSB by month over the period of MEEIA Cycle 1 beginning July 2014 through September 30, 2016. The purpose of this analysis is to demonstrate that the TD-NSB in the MEEIA Cycle 1 is only for the past and not ongoing. This analysis was calculated under the terms of the MEEIA Cycle 1 Stipulation compared to an estimated impact on Company revenues using the Throughput Disincentive ("TD") methodology adopted in the MEEIA Cycle 2 Stipulation. The analysis assumed an annualization adjustment of energy savings beginning in the first month of the test period through the month ending where rates are effective in this case. The total TD-NSB over that period was $17,815,391 as compared to an estimated impact on Company revenues using the MEEIA Cycle 2 TD methodology of $17,935,664, or a deficit of $120,273. (Schedule TMR-11)

Q: Would you explain how TD-NSB was determined in your analysis?

A: The first thing to understand is how the 26.36% TD-NSB Shared Percentage was determined in connection with the Company's MEEIA Cycle 1 Stipulation and Agreement. Lost margins were projected based on projected energy savings targets and assumed margin rates for residential and non-residential customers and projected timing of future rate cases at 18-month intervals. The present value of the projected lost margins was divided by the projected net benefits from energy savings. Net benefits were estimated as the present value of estimated avoided capacity and energy costs resulting from these project energy savings over the measure lives for such savings less the present value of program costs budgets. This 26.36% TD-NSB Shared Percentage was then multiplied times the computed net benefits based on actual energy savings less discounted actual program costs.

Q: How was the estimated impact on Company revenues using the MEEIA Cycle 2 TD methodology determined?

A: The estimated impact of actual energy savings kWh sales by customer class by month was computed based on projected load shape percentage for each energy efficiency program for each month. The load shape percentage is the expected normalized savings expected from each specific program (essentially it is weather normalized). These estimated kWh sales by customer class by month were multiplied by margin rates for each customer class by month. This estimate is based on the Company's proposed adjustment including MEEIA Cycle 1 energy savings through June 30, 2016.

Q: Did you estimate the impact of Staff's exclusion of MEEIA Cycle 1 and Cycle 2 energy savings from this annualization adjustment?

A: Yes, the additional lost annual revenues as of November 2016 for cycle 1 and cycle 2 are \$6.643 million and \$1.710 million respectively, for a total of \$8.353 Million. This represents nearly 121,933 MWh's that need to be adjusted out of the case for both unit sales and sales revenues. (See Schedule TMR-7)

III. FUEL ADJUSTMENT CLAUSE

Q: Which non-KCP&L witnesses are you addressing regarding the FAC?

A: I will address:

1) Staff witnesses David Roos and Alan Bax
2) MECG witness Michael Brosch
3) MIEC witness James Dauphinais
4) OPC witnesses John Riley and Lena Mantle

Q: Please discuss Mr. Roos' testimony concerning the FAC.

A: Mr. Roos along with MIEC witness Mr. Dauphinais have proposed the complete exclusion of SPP Admin, NERC and FERC fees from the FAC as well as all transmission not used to transmit electric power it did not generate for its own load or to transmit excess electric power it is selling to third parties located outside of SPP. The Company disagrees with this position as discussed later in my testimony. The Company continues to support the inclusion of transmission costs included in FERC accounts 565, 561.4, 561.8, 575.7, 928 as necessary, volatile and not controlled by the Company costs to transport power. The Company also continues to support the inclusion in the base FAC calculation a level of these costs at the average of the budgeted 2017 and 2018 costs. This is discussed in the Company's direct testimony as well as in my rebuttal testimony.

Q: Does anyone else discuss transmission costs as it relates to the FAC?

A: Yes, Mr. Brosch uses the example of an FAC in his argument against tracking mechanisms in general. He states that the use of an FAC causes the Company to be apathetic to increases in tracked fuel and purchased power expenses.

Q: Do you agree with his assessment?

A: No. The Company continues to support the fact that these costs are primarily outside the control of the Company, are volatile and unpredictable, and the Missouri legislature enacted the statute that allows for the FAC. The Company has a responsibility to operate in an efficient and ethical manner. Allowing the Company to recover its prudently incurred costs is a basic premise of the regulatory construct.

Q: Does Mr. Roos have other areas of discussion relating to the Company's FAC?

A: Yes. Both Mr. Roos and Mr. Riley recommended that the Company suspend all of its natural gas and natural gas to cross-hedge purchased power hedging activities. Company witness Wm. Edward Blunk addresses this issue in his Rebuttal Testimony, however one aspect of suspending hedging practices impacts the FAC. Currently all gains and losses resulting from the Company's hedging activity associated with hedging for natural gas (cross-hedging related to purchased power and natural gas fuel hedging) run through the FAC. As was done in the most recent GMO case, the unwinding of the current hedges as well as existing gains and losses were allowed to be included in the FAC. The Company expects that the ceasing of hedging for KCP&L MO will be implemented in the same manner. In addition, it is important to keep the hedging language in the FAC so that if there were a change in the natural gas and power markets that showed a need to initiate a hedging program in the future, the costs of that program would be included in the FAC. Note that Staff witness Mr. Roos also made the recommendation that the Company suspend hedging. Staff's testimony however did say that the suspension would be consistent with the Non-Unanimous Stipulation and Agreement, Filed September 20, 2016, in Rate Case No. ER-2016-0156. As an alternative to keeping the hedging language in the FAC, the Company would be agreeable to mimicking the outcome of Rate Case No. ER-2016-0156 where after notifying the parties, the Company can begin a new hedging program and defer the costs in a regulatory asset (or liability) until its next rate case.

Q: What issue has Mr. Bax addressed?

A: Both Mr. Bax and Mr. Roos discuss the requirement associated with the Company having an active FAC to include in the implementation of its FAC the impact of line losses.

Q: Do you agree with the positions taken by Mr. Roos and Mr. Bax relating to the line losses to be included in the FAC tariff?

A: Yes.

Q: Did you review the testimony of OPC witness Lena Mantle regarding modifications to the FAC?

A: Yes

Q: At a high level, provide some background on the FAC in relation to Ms. Mantle's testimony.

A: The KCP&L FAC was recently approved in Case No. ER-2014-0370, which went into effect September 2015, a little over 12 months ago. It was designed almost identically to the GMO FAC approved on September 28, 2016 in Case No. ER-2016-0156 and includes similar costs and revenues to those included in other FAC's, including Ameren's and Empire's. The recommendations made in Ms. Mantle's testimony are an overly restrictive attempt to re-define fuel and purchased power costs and revenues in a manner that is at odds with the common understanding of the components of fuel and purchased power costs and that would, if adopted, improperly exclude from the FAC legitimate costs that have been included in the FAC since its inception. Ms. Mantle was very involved in the processes which led to our FAC tariffs, which now include a significant amount of detail-which she actively argued for. She now seems determined to remove many of these same costs and revenue components from the FAC. The burden that Ms. Mantle seeks to impose on KCP&L is unreasonable and not required by the Code of State Regulations. I also believe her recommendation is contrary to the intent of the legislation which established the FAC. I have been involved in FAC issues not only for KCP&L, but for GMO early in the FAC's history. I have been the Company's primary witness on the FAC in the last several KCP&L and GMO rate cases. The FAC has primarily included the same costs and revenues, that is, fuel and purchased power costs, including transportation, offset by off-system sales revenues with the components that make up those total costs remaining largely the same. From the Company's perspective, a tremendous amount of detail on the various components of FAC costs and revenues is provided monthly. Together with FAC filings and rate case workpapers, ample information is provided to determine costs and revenues in the FAC. Nonetheless, Ms. Mantle continues to request that a very significant level of cost and revenue detail be included in the tariff language. In an attempt to address Ms. Mantle's concerns the

Company has previously agreed to include sub-account information, as well as a list of specific SPP charge types in the tariff. In FAC's submitted by other Missouri utilities, details at the sub-account level have not been included in the tariff sheets, and are not necessary. Prudence reviews are conducted regularly by the Commission Staff to ensure the FAC is operating in compliance with the tariff and the rules of the Commission. Based on the level of scrutiny applied to the FAC by so many parties, the recommendations made by Ms. Mantle are unnecessary and unreasonable.

Q: What recommendations has Ms. Mantle made?

A: On page 3 of her Direct Testimony, she has recommended changes to the FAC that she claims (1) will provide KCP&L with a reduction in risk regarding recovery of fuel and purchased power expense, (2) will reduce the complexity of KCP&L's FAC, (3) will increase the transparency of the FAC, and (4) will reduce the potential for errors in the FAC.

Q: How does Ms. Mantle propose to accomplish these goals?

A: Page 4 of her Direct Testimony, contains the following recommendations: The only costs included in the FAC should be: (1) Delivered fuel commodity costs including, inventory adjustments to the commodities, adjustments to cost due to quality of the commodity and taxes on fuel commodities; (2) the cost of transporting the commodity to the generation plants; (3) the cost of power purchased to meet its native load; and (4) transmission costs directly incurred by KCP&L for purchased power and off-system sales.

These costs would be offset by: Off system sales revenue, net insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC.

The Company believes that, contrary to the above stated recommendations, Ms. Mantle is actually seeking to exclude a significant number of components of fuel, purchased power, transportation and off-system sales (by excluding many SPP charge types). For example, her recommendation only recommends the energy and capacity components of purchased power. This leaves out many other purchased power components such as congestion, hedging in the form of Auction Revenue Rights ("ARR")/Transmission Congestion Rights ("TCR"), ancillary services and over or under recovered losses.

Q: Will Ms. Mantle's recommendations achieve her stated objectives?

A: No. Ms. Mantle's recommendations will increase KCP&L's risk of not recovering proper fuel and purchased power expenses, not reduce it. Her recommendations will increase the complexity of KCP&L's FAC and increase the potential for errors in the FAC.

Q: Does Ms. Mantle propose any other changes to the FAC?

A: Yes, she also proposes to replace the current 95%/5% "sharing mechanism" with a 90%/10% formula that no other Missouri utility is required to use.

Q: What benefits does Ms. Mantle claim will be achieved by her proposed changes to the FAC?

A: On page 5 of her Direct Testimony, she lists several claimed benefits of her recommendation, including consistency with Section 386.266.1 RSMo[3], increased transparency and tariff simplification.

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[3] All statutory citations are to the Missouri Revised Statutes (2000), as amended.

Q: Do you agree with the recommendations made and the reasoning behind the recommendation made by Ms. Mantle?

A: Not at all. I believe Ms. Mantle's recommendations would create more complexity and less transparency. The FAC mechanism is designed to track *changes* in cost and revenue components between rate cases. The important question then is whether KCP&L will be able to recover increases (or whether customers can benefit from decreases) in the net cost of certain volatile components of fuel, purchased power and transportation that OPC seeks to exclude from the FAC. Finally, OPC's proposal does not promote efficiencies. To the contrary, it creates disincentives to improve efficiencies.

Q: Please explain the basis of your disagreement with the majority of Ms. Mantle's testimony.

A: I'll take each of Ms. Mantle's benefit claims one at a time, then summarize my overall position at the end of this section of my testimony.

Q: Do you agree that the changes proposed by Ms. Mantle will provide for consistency with Section 386.266.1?

A: No. KCP&L's FAC tariffs are already consistent with the statute. The statute does not define the terms Fuel, Purchased Power, Transportation or Off-system Sales. However, the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USoA") does provide definitions for these terms (transportation includes transmission expense according to a Missouri Court of Appeals decision) and provides guidance for where certain costs should be recorded. KCP&L follows the USoA in determining where costs should be charged. Therefore, there is no need for Ms. Mantle to re-establish what fuel, including transportation, purchased power costs and revenues are. These terms are widely understood throughout the industry, are outlined in the USoA, and are reported annually on the FERC Form 1. Please see Schedule TMR - 8 for a listing of definitions for each of the FERC accounts that have been typically included in the FAC's in Missouri.

Q. **Has the Commission recognized that fuel, purchased power and transmission costs consist of far more components than OPC recommends for inclusion in KCP&L's FAC?**

A. Yes. All of the Commission-approved FAC's in Missouri reflect the inclusion of far more components of fuel, purchased power and transmission costs than are recommended by OPC. The Commission has approved tariffs with these components since 2007. Moreover, the Commission has approved dozens of FAC rate adjustment filings that reflect far more components than OPC recommends in its proposal.

Q. **Do you disagree with Ms. Mantle's contention on page 6 of her Direct Testimony that costs for the fuel "commodity" itself, transporting that commodity to KCP&L's generating facilities, and the purchased power to serve native load are the "purest" definitions of fuel, transmission and purchased power costs?**

A. Yes, I do. The definition Ms. Mantle argues for now seeks to exclude a large number of fuel and purchased power cost components recognized as the cost of fuel and purchased power by the FERC USoA, industry practice and this Commission's own definition of fuel, transmission and purchased power costs, as evidenced by its treatment of these cost components over many years.

Q. Do you agree with Ms. Mantle's view that her definition of fuel, transmission and purchased power costs is consistent with Section 386.266.1?

A. No. FERC and the industry use the terms fuel, transmission, and purchased power much more broadly than OPC recommends. More importantly, the Commission, Staff and OPC, until recently, have recognized that it is proper to define those costs as they are defined today in KCP&L's tariff and in the proposed tariff submitted by KCP&L in this case. In fact, just a few months ago the Commission approved GMO's FAC tariff that includes the very components that OPC seeks to exclude now. OPC's recommendation is significantly at odds with the FAC statute and the cost components now found in KCP&L's and other Missouri utilities' FAC's.

Q: Has Ms. Mantle proposed to limit components of costs properly included in the fuel, purchased power, transmission and off-system sales accounts found in the USoA issued by FERC in the Code of Federal Regulations?

A: Yes. As indicated above Ms. Mantle is proposing to significantly limit the components of costs to be included in the FAC. She is not, however, proposing to limit any off-system sales revenues from flowing through the FAC.

Q: Why is this a problem?

A: It results in an inconsistent treatment of costs and revenues. Ms. Mantle proposes to exclude many components of fuel cost and purchased power, and attempts to define "pure fuel" as well as "true purchased power and off system sales" on page 9 of her Direct Testimony. She indicates later on page 24 of her Direct Testimony that such exclusion would not result in KCP&L not recovering the non-fuel and purchased power costs that KCP&L proposed to be included because these costs "would still be included in the revenue requirement." She goes on to say that including these costs in the FAC removes the incentive to take action to decrease non-fuel and non-purchased power costs. This claim has been consistently rejected by the Commission. On page 7 Ms. Mantle's recommended FAC would limit purchased power costs to the cost of energy from long-term bilateral contracts, capacity charges from bilateral contracts that change annually or more frequently, and energy purchased on the SPP integrated market to meet native load or to make off-system sales. These recommendations attempt to exclude many legitimate components of fuel and purchased power costs. The Rebuttal testimony of KCP&L witness Wm. Edward Blunk discusses how these components are interrelated with complex trade-offs. He also shows how Ms. Mantle's "cherry picking" scheme can have unintended consequences.

Q: **How do you respond to Ms. Mantle's suggestion that these items be excluded from the FAC?**

A: What Ms. Mantle fails to point out is the purpose of an FAC is to address volatility and uncertainty in fuel, purchased power, and transmission costs, as well as the volatility in off-system sales. The Direct and Rebuttal Testimonies of KCP&L witness Wm. Edward Blunk discuss volatility in these markets. Page 6 of Ms. Mantle's Direct Testimony can be read to suggest that the drafters of Section 386.266.1 did not intend for items such as fuel adders, fuel handling, contractor costs, spinning reserve costs, and startup costs be included in an FAC. However, the statute also does not list "energy" or "capacity." Moreover, each of these items is essential components of fuel or purchased power costs. It is not operationally practical to burn coal or purchase power from the SPP Integrated Market without purchasing these items. For example, start-up costs are necessary to start a generating plant in order to produce electricity. USoA Account 555 ("Purchased Power") lists "spinning reserve capacity" as a cost that should be recorded there along with a long list of costs that are not simply capacity or energy. Excluding appropriate components of fuel and purchased power costs from the FAC would increase the potential for errors and disagreements among the utility and those reviewing the costs either in rate cases or prudence audits.

Ms. Mantle's recommendations are also inconsistent with the Commission's FAC rules and the legislation's purpose. The statute does not define the terms fuel, purchased power, transportation or off-system sales, but grants the Commission authority to establish rules to administer the FAC. These rules and the Commission's nearly 10 years of administering them demonstrate that purchased power is much more than capacity and energy.

Ms. Mantle's recommendation also excludes components of purchased power from the FAC which hedge the cost exposure for customers. This is an imbalanced approach based on her definition of what constitutes purchased power. Ms. Mantle is trying to "cherry pick" which elements of purchased power are included or excluded from the FAC.

Q: Are there any other costs Ms. Mantle recommends be excluded from the FAC?

A: Yes. She proposes to exclude charges from the FAC related to the SPP Integrated Market. She categorizes these charges not as fuel or purchased power costs, but rather as costs and revenues incurred through doing business with SPP. Ms. Mantle claims that these charges were not envisioned when the law was drafted.

Q: What is your response to Ms. Mantle's recommendation on exclusion of charges related to the SPP IM?

A: In order for the Company to provide electricity to its customers, it participates in the SPP IM. By doing so, all electricity it produces is sold into the market and all electricity it needs to serve its load is purchased from the market. In order to bring transparency to its energy market, the SPP has set up numerous charge codes (which include both expense and revenue) to account for these transactions, but overall each cost or revenue is a component of either off-system sales revenue or purchased power. The Company cannot elect to pay some of those charges and not others and still provide power to its customers. Breaking the costs and revenues apart and eliminating some of these charge codes from the FAC makes for a skewed look at how the market works and how the Company incurs costs.

Q: Are these charges incurred by participation in the SPP IM new costs to the Company?

A: No. While the SPP assigns a dollar value to these costs and revenues, the Company has always incurred these kinds of costs and incurred them before the market began. For example, the Company has always had to incur costs for spinning reserve. These costs were included as a part of either the fuel or purchased power that was necessary to serve customers. Just because SPP now assigns a specific dollar value to these activities does not make them new or a non-fuel or purchased power cost.

Additionally, the SPP also assigns a dollar value to congestion as it flows on the grid. As congestion is not new, these costs would have been previously incurred as increased purchased power prices. In order to protect the integrated utility's load from the costs of congestion the SPP IM has created an ARR/TCR market. The purpose of the ARR or TCR revenues is to offset the higher congestion paid as a part of the price of purchased power in the SPP IM. Ms. Mantle has proposed to eliminate any TCR charge codes from the FAC thus leaving the Company's customers exposed to these higher purchased power prices. This further portrays Ms. Mantle's method of "cherry picking" and her lack of knowledge regarding how energy markets are structured. The market works as a whole, and the costs and revenues from that market must be taken together as a whole because there are complex trade-offs as the market is co-optimized for minimum total cost given prevailing security and operating constraints.

Q: Why must all costs and revenues in the SPP IM be considered together?

A: The interrelationships of the costs within a co-optimized market must be taken as a whole otherwise the actual cost of producing or purchasing the electricity will be misrepresented. In a co-optimized market, SPP seeks to dispatch each utility's assets in the most efficient manner for the entire SPP footprint. This is accomplished by dispatching a combination of energy and/or ancillary services (Regulation Up, Regulation Down, Spinning Reserves and Supplemental Reserves) to make each utility the most efficient. It appears that Ms. Mantle has suggested that all ancillary charges be excluded from the FAC. In fact, SPP may dispatch units to provide ancillary services as opposed to energy. Under Ms. Mantle's recommendation, it appears this type of dispatch would mean any revenues received for these services would not be included in the FAC while a utility's customers would be paying for power purchased from SPP.

Q: Could SPP instruct a Company to run a unit even if it was not efficient?

A: Yes. For example, if SPP believes there is an issue on the grid relating to voltage control, a utility could be instructed to run a unit that is unprofitable for a particular time period. In such cases that utility could receive a "Make Whole Payment" so its customers would not have to pay more for fuel and operational costs than what the power was sold for in the market. It appears Ms. Mantle's proposal will exclude the charge code representing this payment. This is unreasonable and appears to reflect her lack of understanding of its purpose.

Q: Are there serious issues with excluding SPP's IM charge codes from the FAC?

A: Yes. The purpose of these charge codes is to break out purchased power and off-system sales cost and revenue components to facilitate the efficient operation of the IM. The costs and revenues that these charge codes reflect were incurred to lower total power production costs which ultimately benefits customers. No one, other than Ms. Mantle, has advocated excluding from the FAC those costs that are associated with the savings that are achieved by participating in the SPP IM. Because all of the savings that justify these IM costs will flow through the FAC, it would be unfair and inconsistent to divorce the production cost savings from the costs that made those savings possible. Such exclusion could be a violation of Section 386.266.4(1)'s requirement that an FAC be reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity. An FAC that separates production cost savings from the costs that made those savings possible would impair the Company's opportunity to earn a fair return on equity.

Q: Why do you believe that leaving these costs out of the FAC would impair the utility's opportunity to earn a fair return if they are reflected in the overall cost of service of the Company outside of the FAC?

A: The reason that I make this statement is because of the volatility that exists in all commodity costs, The SPP IM is designed to decrease the costs of each member utility because it is operating as part of a larger group of utilities in a coordinated fashion. This fact does not eliminate volatility in market costs and revenues. As KCP&L witness Wm. Edward. Blunk discusses in his Rebuttal testimony, it can actually increase volatility.

Q: Ms. Mantle discusses something she calls "true purchased power." What does this mean?

A: The Commission used the phrase "true purchased power" as a short-hand phrase to mean "electric power it [the utility] did not generate to its own load." The phrase is contained in the Commission's 2015 Report and Order in the Empire District Electric Company rate case No. ER-2014-0351, and has been used in subsequent decisions. However, that phrase has never been used to exclude from an FAC any SPP IM charges that relate to serving native load and providing benefits to customers.

Q: Are there issues with excluding all or part of the transmission costs from the FAC based upon her definition of true purchased power?

A: Yes. On page 9 of Ms. Mantle's direct testimony, she states that OPC recommends the Commission restrict the transmission costs included in KCP&L's FAC to the costs of transmission that can be directly tied to purchased power and off-system sales. She goes on to state that the only costs that can be directly tied to true purchased power and off-system sales is Point-to-point ("PTP") and network integration transmission services ("NITS") fees directly tied to true purchased power and off-system sales.

Q: Does this distinction as presented by Ms. Mantle make sense?

A: No. For example, although she proposes to exclude all Base Plan Funding costs, these costs are charged to the Company as PTP and NITS just like the other transmission schedules are charged to the Company. See the rebuttal testimony Company witness Don Frerking for more discussion of why Base Plan Funding costs are necessary for KCP&L to make purchase power and off-system sales and therefore should be included in the FAC. A portion of Base Plan Funding costs are charged based on the total MW of PTP service reserved by the Company, and the remaining portion is charged based on the Company's retail load, which is served by NITS. In other words, these are transmission service costs directly tied to load. These are not costs expended by KCP&L to build transmission assets but rather are transmission charges that KCP&L must pay for the mWhs it purchases to serve its load. This distinction was recognized by the Commission most recently in Ameren Missouri's rate case No. ER-2014-0258 when its April 29, 2015 Report and Order approved tariff language proposed by Ameren and OPC that included MISO charges similar to the SPP charges that KCP&L seeks to include in its FAC.

Q: Are the transmission costs OPC wants excluded from the FAC integral to the Company providing power at the most efficient cost?

A: Yes. Transmission and the charges that pay for that transmission are a critical component of SPP's ability to transport the Company's electricity to its customers in an efficient and effective manner. SPP's regional control over the transmission of electricity is consistent with national energy policies implemented by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. SPP's IM was implemented in response to those policies. Through the IM and the transmission that enables the IM, SPP is working to minimize the total cost of electricity within the region.

Q: Who gets the benefits of SPP's efforts to minimize the total cost of electricity through the co-optimization of energy production and the transmission of that energy?

A: Customers. This is because the energy and transmission items that the Company has proposed for the FAC will match costs and benefits, and will pass the net of those costs and benefits to customers.

Q: On page 12 of Ms. Mantle's testimony she recommends including the revenues for off-system sales of capacity. Do you take issue with this?

A: No, not as long as both capacity revenues and costs are included. In the past, both Staff and OPC have insisted that any capacity agreements that are longer than 12 months in length should be excluded from the FAC for both revenues and expenses. This statement in Ms. Mantle's testimony seems to imply that all capacity revenues and costs should be included in the FAC.

Q: Should insurance recoveries, subrogation recoveries and settlement proceeds be included in the KCP&L FAC?

A: If the recoveries or settlements are related to prior increases in cost included in the FAC, those recoveries should be flowed back to the KCP&L's customers through the FAC. If, however, they did not relate to previous increases in the FAC, they should not be included.

Q: Do you believe that there is a lack of transparency in KCP&L's FAC?

A: No.

Q: Why has the Company not provided the level of detail Ms. Mantle has requested?

A: The Company has provided significant amounts of information and explanations to Ms. Mantle in an attempt to clearly identify the costs and revenues which flow through the FAC. Each time more information is provided, she uses this information to argue that the definitions are not clear, that the costs are not completely identified, and that the information is not comprehensive. It appears that no matter what level of detail or what level of explanation is provided by KCP&L, Ms. Mantle remains dissatisfied. Ironically, despite her past requests, she now claims that the FAC has too much detail and is too complex.

Q: Do you agree with Ms. Mantle's Direct Testimony where she recommends that fuel, purchased power and transportation/transmission be defined as a small subset of the components that make up these items/?

A: No. On page 13 of Ms. Mantle's direct testimony she recommends that the Commission approve limited specific components of costs and revenues for KCP&L's FAC. She indicates that the costs and revenues provided by KCP&L for inclusion in the FAC are not transparent (p. 14) and provide a disincentive for the Company to implement cost efficiencies.

FERC's Uniform System of Accounts ("USoA") provides a description of the accounts to be used for expenses. It is not possible for FERC or any other regulatory body to address every situation. However, the USoA is very clear as to where expenses should be recorded. For example, FERC mandated accounts 501 (Fuel), 509

(Allowances), 518 (Nuclear Fuel Expense), 547 (Fuel), 555 (Purchased Power), 561.4 (Scheduling, System Controls and Dispatching Services), 561.8 (Reliability Planning and Standards Development Services), 565 (Transmission of Electricity by Others), 575.7 (Market Administration, Monitoring and Compliance Services), 447 (Sales for Resale), 928 Regulatory commission expenses and 456.1 (Revenue from Transmission of Electricity of Others) provide specific and defined guidance as to the costs or revenues to be recorded to these accounts for the purchase or sale of electricity or transmission. Ms. Mantle insists that every possible cost scenario be listed in the tariff and that only current scenarios be listed; otherwise, KCP&L will not be able to recover that scenario's cost through the FAC. She then complains that following this process leads to excessively long tariffs. Her solution is to excessively limit the costs to be included in the FAC, thus ignoring how costs are accumulated across the country in a standardized and uniform process that is required by FERC under the USoA.

Q: **On pages 13 and 14 of Ms. Mantle's direct testimony she claims that the Company is requesting FAC recovery for much more than fuel, purchased power, transmission and off-system sales. Do you agree with this assessment?**

A: No. She misrepresents how the Company appropriately accounts for the costs associated with the generation, purchase and transportation of its power. For example, fuel handling costs are appropriately recorded into FERC accounts 501 and 547, which could include meals, lodging, and other expenses for the individuals who procure the fuel because fuel procurement costs are a component of fuel costs. However, the FAC statute contemplates the recovery of expenses related to the procurement of fuel and purchased power. The USoA itself provides that items related to "supervising purchasing and handling of fuel" should be charged in account 501 as a fuel expense.

Q: **Do you believe the Company should be allowed to recover all costs in FERC accounts 501, 509, 518, 547, 555, 565, 561.4, 561.8, 575.7, 928, 456.1 and 447?**

A: No. The Company has never requested the recovery of any purely labor costs through the FAC and has instead reflected them in base rates as part of the Company's labor normalization process. Additionally, the Company has agreed to exclude capacity contracts greater than 1 year in length based on the argument that these costs are more akin to acquiring resources. The Company has also requested only the FERC assessment costs in account 928 to be recovered within the FAC as other regulatory commission expenses are recovered on an annualized and normalized basis in the revenue requirement of a rate case proceeding. The Company does believe all other costs and revenues allowed to be recorded in these accounts by FERC should be included in the FAC.

Q: **Ms. Mantle states on page 15 of her Direct Testimony that by approving a sub-account but not a specific cost the Commission "would be opening the door to allowing all types of costs to be included" in the FAC if the Company records the cost to a Commission approved account. She states on page 15 that the Company is currently attempting to reclassify costs so that they will be includable in the FAC. Do you agree with this reasoning?**

A: No, not at all.

Q: **Ms. Mantle claims that this shifting of costs is exactly what the Company is already doing. How do you respond?**

A: As the Company explained to Ms. Mantle in a meeting regarding the FAC in this case, based upon operational changes at the power plant, costs previously recorded in FERC account 502 and not included in the FAC are now more appropriately considered fuel costs and are recorded in FERC account 501. Given that the Company knows that these costs were previously included in base rates and had not been included in the base calculation for the FAC these costs have been excluded from current FAC filings. In this case the Company has requested that these costs be included in the FAC base calculation.

Q: **Do you agree with Ms. Mantle that there are transparency issues associated with the Company's FAC?**

A: No. Ms. Mantle is requesting a level of detail and assurance of perfection that is unnecessary and unreasonable. The fact is that the Company follows the FERC USoA to record its costs and revenues, and this process permits thorough prudence reviews and audits to occur. Limiting the costs and revenues which are included in the FAC will only serve to diminish the effectiveness and transparency of the FAC overall while increasing the potential for error by excluding specific costs that are correctly recorded in their appropriate FERC accounts. FERC account numbers already provide for those limits because the USoA defines what is included in its accounts which neither KCP&L nor any other party can change. Assuming Ms. Mantle wants a simplified tariff and only a subset of those items included in the specific FERC accounts to be included in the FAC, her objective would be better served by using words in the FERC defined accounts and prime account numbers to describe what is included or excluded from the FERC account definition.

Excessively picking and choosing which fuel and purchased power costs should be excluded or included in the FAC needlessly complicates the process of preparing and reviewing the FAC. It also increases the likelihood for error and does not provide additional transparency. Further, the Commission and OPC have access to the information they need to understand costs and revenues in the FAC and to determine if the Company is complying with its tariff. Significant details about costs and revenues are provided in each and every FAC monthly report. Those reports and the periodic FAC filings allow others to determine costs and revenues in the FAC, and to verify the calculations presented there.

As proposed by Ms. Mantle, reducing the number of components of fuel, purchased power and transmission included in the FAC will prevent KCP&L from recovering the costs that the Commission has previously approved in prior FAC's for KCP&L and other Missouri utilities. If simplification is the goal, it would be preferable if the FAC were constructed at the FERC USoA account level. In any event, the Commission should reject these claims by Ms. Mantle which no other party to this case has asserted.

Q: Why did the Company file FAC tariff sheets with subaccount listings if it would prefer FERC prime and descriptions of the costs?

A: KCP&L has only had an FAC since the end of September 2015. However, GMO has had an FAC since 2007. The Company has watched the changes that have been made to the FAC tariffs over time and has tried to comply with the changes requested by Staff and OPC. Since that time, GMO settled its rate case, and agreed that its FAC tariffs would be like the KCP&L tariffs. Ms. Mantle took that statement to the extreme by not allowing costs recorded in account 501420 GMO sub-account, because those same costs (that are allowed in KCP&L's FAC) are recorded in account 501400 for KCP&L. The Company does not believe that disallowing costs based upon different utilities' accounting systems was intended in the original FAC legislation. Sub-accounts have a managerial accounting purpose only. FERC prime is the guiding principle behind how costs are recorded on the Company's books and records. FERC prime, as explained in Schedule TMR - 8 should be the main guideline within the tariff with the description of costs spelling out any items that should be excluded.

Q: Ms. Mantle claims beginning on page 16 of her Direct Testimony that making her proposed changes would limit disincentives to achieving efficiencies. Do you agree with this assertion?

A: No.

Q: Please explain why.

A: Excluding certain cost and revenue components appropriately recorded as fuel, purchased power, transmission and off system sales may in fact provide a disincentive for utilities to actively manage certain exposures by divorcing the underlying risk from the tools used to manage that risk. Please see further discussion of this issue in the Rebuttal Testimony of Wm. Edward Blunk in this case.

Q: Do you agree with Ms. Mantle that the changes she proposes would simplify FAC prudence audits?

A: No, I do not.

Q: Please explain.

A: Although there is no process that is 100% perfect for auditing the books and records of any company, KCP&L properly records its costs according to the FERC USoA. The Company keeps detailed records which it provides for review by Staff and others within the prudence review process. The Commission's regulations require that a utility with an active FAC file a rate case every four years. Prudence reviews are required at least every 18 months. Monthly FAC information is provided along with quarterly surveillance reports. Audits of the FAC would become more difficult and confusing if Ms. Mantle's recommendations were adopted. Cost and revenue components which offset costs and revenues in the FAC or which are alternatives to those costs in the FAC would be removed from the FAC if her proposals were adopted. Auditors would still need to look at all cost and revenue components outside the FAC to determine whether both FAC and non-FAC components were appropriately recorded and whether they were prudent.

Ms. Mantle cites an error on page 20 in GMO's FAC that happened as a result of changes in the billing that occurred with the integration of the Entergy companies into the MISO energy markets. As soon as Staff pointed out the error which they found in their analysis of a data request response in a recent rate case, GMO took immediate steps to pass those costs back to its customers. If a mistake is made, the Company always fully cooperates with the review and audit process, and takes internal steps to help ensure that future mistakes are not made. Reducing the effectiveness of the FAC by eliminating costs in the hopes of simplifying the review and audit process is unreasonable and unnecessary as the FAC process in place today is working.

Q: **Next, Ms. Mantle claims that removing costs from the FAC would simplify the FAC tariff sheets, particularly the listing of SPP IM charge types. How do you respond to this claim?**

A: Although the tariff itself might be simpler, it would complicate the administration and audit of the FAC. In actuality her recommendations would thwart the FAC because they are contrary to the purpose of Section 386.266 and would prevent KCP&L from recovering, and customers from receiving decreases in, legitimate fuel and purchased power costs. Ms. Mantle has misrepresented the costs and revenues for doing business in SPP's Integrated Marketplace. These are not the costs of "doing business through an RTO," as Ms. Mantle claims on page 22 of her Direct Testimony. These are the costs of providing power to the Company's customers by using a co-optimized integrated market. As I discussed earlier, these costs and revenues in their entirety are considered purchased power and off-systems sales as defined by FERC.

Q: **Do you find it ironic that Ms. Mantle would complain about the complexity of the FAC tariffs on pages 22-23 of her Direct Testimony?**

A: Yes. Over the years, Missouri utilities have agreed to revise the content of their FAC tariffs to provide more information to various parties, particularly to OPC and Ms. Mantle. Now, she is complaining that the tariffs are too complex because they contain too much information. However, the level of complexity she and others have requested has further complicated the process. FERC's USoA is required to be used by all public utilities. Certain types of costs are to be recorded on the books and records in specific FERC accounts. The use of FERC accounts associated with fuel, purchased power and off system sales are uniform, required, and generally understood across the country.

Every cost and revenue must be categorized by the Company according to the USoA. Ms. Mantle continues to attempt to re-define the USoA and its definitions of fuel and purchased power costs at a distorted and microscopic level. She has gone from requesting identification of costs at the sub-account and even resource level to now categorizing costs at an even more detailed level of minutiae. The intent of the USoA was to identify costs at the FERC account level; not at the sub-account level. The intent of the sub-account is to allow the Company to better manage its business. When Ms. Mantle reaches for the sub-accounts she is delving into micro-management of the Company.

In a related issue, KCP&L has proposed to recover a cost if it is "like" an SPP cost listed in the tariff sheet. While costs included at the FERC accounts generally do not change, it is not unusual for the SPP to change a charge code, whether it is a re-naming convention or re-classification. But even with that re-naming or re-classification, it is not a new cost. These changes are made by SPP, and the Company has no control over these changes. Under Ms. Mantle's suggested tariff changes, many charge types (which include revenue as well as cost components) would be excluded from the FAC.

Q: **What do you say about Ms. Mantle's claim on page 22 of her Direct Testimony that many of the SPP charges that KCP&L is requesting in its FAC were not envisioned when Section 386.266 was enacted in 2005?**

A: I disagree. The costs reflected in those SPP charges were always part of the cost of purchased power. The difference now is that SPP has broken down these costs and presented them as cost components. The fact that these cost components did not exist in 2005 is not surprising since the SPP market was not launched until 2007. The costs and revenues of the SPP market, however, are appropriately identified as purchased power and off system sales. KCP&L's current FAC tariffs comply with the Commission's regulations and the law. Ms. Mantle's view is based upon an unreasonably narrow interpretation of what are proper FAC costs and revenues, as well as a lack of understanding of how energy markets work today. Her recommendation to exclude SPP IM charges is contrary to the Commission's FAC rules and the intent of the legislature when it enacted the FAC statute.

Q: **How do you respond to Ms. Mantle's claim on page 24 of her Direct Testimony that the Company will still recover the majority of its current FAC costs in its revenue requirement?**

A: Her view is contrary to what the FAC is designed to achieve. The FAC was established because of the volatility and unpredictability of the fuel and purchased power costs. Her proposal would not allow for the timely and adequate recovery of these costs by KCP&L.

Q: **Do you agree with Ms. Mantle's assertion that the proposed changes to the "sharing mechanism" from 95%/5% to a 90/10 formula would provide for a greater incentive for cost management?**

A: No. Ms. Mantle states on page 25 of her Direct Testimony that under a 90/10 cost recovery mechanism even if costs increase 20%, then KCP&L will still collect 98.3% of its fuel costs. She claims that a 90/10 sharing mechanism would provide more of an incentive to KCP&L to decrease its FAC costs. The problem with her proposal is that KCP&L has a very limited ability to control its FAC-related costs. She cites no evidence on how much of KCP&L's prudently incurred costs would not have been recovered if her proposal had been in place in prior periods. A 90/10 sharing mechanism does not further incentivize KCP&L to manage fuel, purchased power and off-system sales. The vast majority of FAC's in place for electric utilities in this part of the country reconcile recovery at the 100% level. KCP&L competes for capital with these companies and would be further disadvantaged if its FAC limited recovery to 90%. It is also important to remember that fuel costs are volatile, as discussed in the Direct and Rebuttal Testimonies of KCP&L witness Wm. Edward Blunk. The sharing mechanism should not be changed because inconsistent regulatory policy has the effect of eroding investor confidence in utilities and would cast doubt on Missouri's regulatory process.

Finally, it must be recognized that Ms. Mantle's proposal would make KCP&L's FAC different than all other utility FAC's in Missouri, which are all 95/5. It would also penalize the Company by potentially disallowing a larger percentage of costs, and raise unnecessary issues for investors and lenders who would see this as a negative factor relating to KCP&L's operations.

Q: Do you agree with the additional reporting requirements proposed by Ms. Mantle on page 27 of her Direct Testimony?

A: No. Ms. Mantle requests that all of the costs and revenues included in the FAC be listed by sub-account for the current month and the preceding 12 months. She notes that currently costs are aggregated and complains that this provides insufficient detail. Her proposal would add another layer of complexity to KCP&L's reporting which, notably, Staff has not requested. KCP&L does not believe this is necessary for monthly reporting. In particular, the SPP IM charge types, both revenue and expense, have been researched and classified by KCP&L in accordance with the USoA.

Q: Do you agree with this limited listing of items to be included in the FAC?

A: As I said above, I agree that all of the costs net of revenues (except labor, capacity contracts greater than one year in duration and non-FERC assessment costs in 928) referenced in the list previously should be included in the FAC, but I disagree with Ms. Mantle's exclusion of other fuel and fuel related costs that have been historically included in the FAC as these limitations significantly diminish the effectiveness of the FAC and will actually accomplish the opposite of what Ms. Mantle hopes to achieve.

IV. GREENWOOD SOLAR STATION

Q: Would you provide the status of the Greenwood Solar project?

A: Yes. As Staff witness Clare Eubanks indicated, the project is complete and GMP placed the solar plant in service as of June 20, 2016.

Q: Could you explain the issue?

A: Yes. Staff witness Karen Lyons recommends an allocation of the Greenwood Solar System located in the GMO service territory to assign nearly 62.27% of the plant and any related expenses over to the KCP&L system. This allocation is based on the number of customers served in each jurisdiction. Staff further allocated the split between Missouri and Kansas for KCP&L based on a demand allocator. In the prior GMO rate case, Staff recommended an allocation based on energy, rather than customers and demand.

Q: Do you agree with Staff's recommendation?

A: No, I do not. While the proposed allocation methodology places more revenue requirements to KCP&L, it makes absolutely no sense. It makes no sense because to allow the benefits of the energy produced from the Greenwood Solar Facility to benefit GMO, but charge KCP&L for nearly two-thirds of the plant investment (both Kansas and

Missouri). Staff does not address the allocation of depreciation, O&M expenses, taxes, tax benefits and all other costs that would normally be allocated, if such an allocation were made. They simply say that all expenses should be allocated in a similar way.

I addressed this issue in the recent GMO case, ER-2016-0165, as to why an allocation as being proposed does not make sense. I further discussed that if the Commission determines that it is appropriate to make an allocation, I would recommend that a $100,000 cost assignment be made to KCP&L. This would equate to an overall allocation of approximately 50% of the plant and expenses as computed through a cost of service assignment. By simply assigning the fixed amount as I am I recommending, it eliminates all of the allocation and assignment issues that would result from an attempt to somehow share the facility with the two utilities as suggested by Staff. The Greenwood Solar Facility is a small investment and is an effort by the Company to learn about utility owned solar operation.

Q: Doesn't the Company have other power plants that are jointly owned with other utilities?

A: Yes. However, the joint ownerships of these plants are contractually managed and require substantial accounting and management processes to manage the facilities. A substantial effort by each of the joint owners is required in the decisions being made, operations, maintenance, accounting, movement of power, etc. This is not planned with the Greenwood Solar Facility.

Q Can you describe the merits of either no-allocation and an allocation of the Greenwood Solar facility?

A: Yes. The benefits to KCP&L from the investment in the solar project at GMO do not warrant an allocation of any costs of the facility, whether direct or indirect, to KCP&L because not a single electron produced by the Greenwood Solar facility will ever reach the KCP&L system. The Greenwood Solar facility is interconnected to GMO's distribution system and as such all energy from the system is produced for the benefit and use of GMO's customers. As a corporation with multiple operating utilities, many projects, both generation and distribution, are often done at one utility subsidiary and may result in benefits of an intangible nature to the other. One of the benefits identified during the acquisition of GMO by Great Plains Energy was the expertise that GMO had in maintenance of its natural gas plants. That expertise was shared with KCP&L. Likewise, KCP&L had substantial expertise in maintenance of its coal fleet and that was then shared with GMO, without compensation through allocation of costs. KCP&L was one of the first utilities in the nation to implement an automated meter reading system many years ago. Both KCP&L and GMO are now deploying next generation automated metering (AMI) and GMO is receiving the benefit of KCP&L's expertise, without any transfer of costs to GMO for that knowledge. The Company believes it is not appropriate to transfer costs of the Greenwood Solar facility to KCP&L.

Q: If the Commission required GMO to transfer some dollar amount to KCP&L, what would you recommend as an appropriate amount and how it could be done?

A: Yes. The customer allocator proposed by Staff which allocates nearly 65% of the plant and expenses associated with the Greenwood Solar facility away from GMO to be paid by KCP&L. However, it does not recognize the tax savings or energy sales attributed to the operation of the solar facility. I believe that no more than ½ of the overall incremental cost of the solar facility above the costs of a less expensive renewable resource could be allocated to KCP&L, however, I do not believe it should be done by simply placing plant and all off the costs, revenues, taxes and other attributes in the KCP&L cost of service. I would recommend an allocation methodology for the solar facility based on an allocation between an alternative renewable energy source capital costs versus the cost of the solar facility, with the difference between the two allocated equally between KCP&L and GMO. If you looked at wind versus the solar project, the difference in capital would be roughly $2 million for the same size system. This would result in roughly $1 million in capital cost allocated to KCP&L. Because of all the other impacts on the investment such as specific tax benefits, REC's, the energy from the facility, and operating costs which would remain with GMO, using a plant investment allocation is not practical. As such, if the Commission Ordered the Company to make an allocation, I would recommend an allocation of no more than $100,000 to KCP&L in expenses to be reflected in KCP&L cost of service and future ratemaking. While this may seem like a small amount to allocate, I believe that it is representative of a reasonable allocation which allows for the plant, depreciation, expenses, taxes and all other attributes, including energy to remain at GMO, while assigning costs to KCP&L which reflect 50% of the incremental costs of the renewable above wind alternative.

V. CLEAN CHARGE NETWORK

Q: Please explain your understanding of Staff's position.

A: Staff believes that existing law generally requires the Commission to regulate the operation for EV charging stations[4] and recommends adoption of the tariff sheets on the condition that all revenues, expenses and investment related to the Clean Charge Network are recorded below the line to hold ratepayers harmless.[5] While the Company agrees that the Commission does have jurisdiction over EV charging stations, it does not understand Staff's position that this regulated service should be treated below the line. If the service is regulated, it should be treated above the line, unless the Company's investment is determined to be imprudent. While I am not an attorney, I suspect this may not be legal to require a regulated service, but not allow recovery. Staff also recommends some modifications to the tariff.

Q: What tariff modifications does Staff recommend?

A: Staff recommends that the Commission approve the Company's proposed tariff sheets subject to revisions addressing the Session Charge, as defined in the proposed tariff, which staff believes violates § 393.130, RSMo, by permitting unregulated third parties to set a portion of rates.

Q: Please describe the optional Session Charge proposed in tariff?

A: The Session Charge can be applied to specific charging stations with high occupancy rates and would range up to a maximum of $6.00 per hour. The rate parameters are defined and set in Company's proposed tariff. The Session Charge, if implemented,

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[4] *See Staff Report- Revenue Requirement Cost of Service,* Case No. ER-2016-0285, Pp.173

[5] *See Staff Report- Revenue Requirement Cost of Service,* Case No. ER-2016-0285, Pp.173-174

would provide an incentive for EV drivers to move their car once the charge session is complete and allow other drivers access to the charging station. As this is a pilot program, KCP&L requires flexibility to experiment with various Session Charge amounts within the boundaries set by KCP&L and defined in the tariff schedule to ascertain which charges have the greatest influence on EV driver charging etiquette. As proposed, the maximum session charge roughly reflects lost revenue potential of an hour long L3 charge session.

Q: Do you agree with Staff that the optional Session Charge violates § 393.130, RSMo, by permitting unregulated third parties to set a portion of rates?

A: While I am not an attorney, I believe that the Company has properly defined the specific parameters of the optional charge and if the tariff is approved, the Commission is setting a range for the optional Session Charge component. The Company desires the flexibility to design and implement, with input from the host, Session Charges as the need arises. KCP&L is willing to work with the Staff to revise the tariff language to establish a fixed Session Charge that could be implemented once drivers have completed charging.

Q: What other reporting does Staff recommend?

A: On pages 173 and 174 of the Staff's Cost of Service report, Staff suggests "that the Company gather data and report annually to the Commission and interested stakeholders on the impact of electric vehicle charging stations on grid reliability."[6]

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[6] *See Staff Report- Revenue Requirement Cost of Service,* Case No. ER-2016-0285, Pp.173-174.

Q: Do you believe these recommendations can be accommodated by the Company at this time?

A: The Company can work to provide the Commission with annual reports regarding the use of the Company-owned EV charging stations and the impact they have on the Company facilities.

Q: The Company has previously stated that it believes that third-party market involvement can be achieved with EV charging stations. Please elaborate.

A: The Company believes that in the future, private entities may become key players in the charging station market. But that is not the case today. As I understand the current law in Missouri,[7] public utilities are the only entities authorized to provide and charge for public charging stations such as those proposed in this docket. As pointed out in Staff's interpretation, EV charging stations fall within the definition of electric plant[8] and should be treated as such, meaning they are under Commission jurisdiction. Regardless of Staff's and OPC's questioning to the need for the EV charging stations, the fact remains that customers have requested and are utilizing the EV charging stations installed as part of KCP&L's CCN and other networks of charging stations. If the public wants this type of service, which is clearly the case based upon usage data obtained even at these early stages of the program.[9], the utility is the only legal entity in the area authorized to offer the service as proposed, then the Commission should not deny customers access to the

[7] My understanding is based on the Company's filings in EW-2016-0123. Staff's analysis in its legal brief is consistent on this point.

[8] *See Corrected Staff Report: A Working Case Regarding Electric Vehicle Charging Facilities.* File No. EW-2016-0123, pp. 11.

[9] *See* Schedule TMR-9- EV Usage Statistics.

service. The Company believes that utility involvement is vital to the start of the EV market. In fact, if the stations owned by the Company and the few owned by auto manufacturers and auto dealerships were removed from the public marketplace, fewer than 100 public charging ports would be available in the state.

Q: Does the Company believe more EV charging stations will be necessary to satisfy customer demand within Missouri?

A: Yes. Our numbers indicate continued usage growth over time will lead to demand for additional stations. The Company also believes that with the current growth of the marketplace, more stations and more station providers will be necessary. In order for a competitive market to take hold, such as the one suggested by Sierra Club witness Douglas Jester[10], statutory changes would be necessary to allow for third-party's to provide and charge for EV charging station service.

Q: Why do you believe the Commission should approve the Company's proposed tariff and cost recovery related to the CCN?

A: I believe that the Commission should approve the Company's EV tariff and allow recovery of EV charging station costs because:

(1) utilities are the only entity legally authorized to provide and charge for public EV charging stations in Missouri;

(2) program costs and impacts to customers are small in relation to ongoing utility operating costs;

[10] *See Direct Testimony of Douglas Jester on Behalf of the Sierra Club*, Case No. ER-2016-0285, Pp. 6.

(3) the data collected from the program will be instrumental in crafting appropriate regulatory and legislative changes to allow non-utilities to participate in the market, and

(4) securing legislative changes to allow non-utilities to provide the service will take significant time, in the meantime EV drivers need to be provided safe and adequate service

(5) the economic and other benefits flowing from EV charging stations offer value to all customers, Missouri utilities, the Commission and the State of Missouri. These benefits include:

a. Beneficial Electrification: As opposed to EV charging stations owned and operated by multiple entities other than the serving electric utility, installation and operation of EV charging stations as part of the utility's electric distribution system will facilitate efficient use of the electrical grid through increased sales during off-peak times, spreading the cost of operating and maintaining the grid over more kilowatt-hours without causing increased generation investment.

b. Environmental Benefits: Increased EV usage would displace fossil fuel vehicle usage, thereby reducing tailpipe emissions – including particulate matter and ozone emissions in addition to others

c. Economic Development: Increased EV usage should spur regional economic development by attracting auto industry, EV industry and charging station companies to the Company's service territory; it should also assist in local job creation resulting from increased household spending on local goods and services rather than gas at the pump; regional recruitment in competitive job categories such as STEM (science, technology, engineering and math) may also see a boost with increased EV usage in the Company's service territory.

d. <u>Customer Programs</u>: As opposed to EV charging stations owned and operated by multiple entities other than the serving utility, installation and operation of EV charging stations as part of the utility's electric distribution system should enable customer programs for cost-effective demand side management, time-of-use rates and vehicle to grid battery storage and discharge.

e. <u>Cost and Efficiency Benefits</u>: As opposed to EV charging stations owned and operated by multiple entities other than the serving utility, installation and operation of EV charging stations as part of the utility's electric distribution system should reduce the cost of equipment and installation while use of the utility as a standard payment platform should also reduce cost; such efficiencies should ease expansion of the system if deemed appropriate.

Q: Have you any concerns regarding Staff's analysis of Plug-in Electric Vehicle Rate provided by Byron Murray?

A: Yes, the report stated that Staff analyzed and compared the KCP&L Schedule CCN tariff with the Georgia Power Plug-In Electric Vehicle-Time of Use ("PEV-TOU") rate and in Staff's opinion the Georgia model provides proper incentives to charge PEVs in off peak hours.[11] While we generally agree that the Georgia Power PEV-TOU model can provide an effective incentive for EV owners to charge their vehicles at home during off-peak times, it is not a proper comparison. The CCN tariff is for EV drivers charging at Company-owned and operated public EV charging stations. The Georgia PEV-TOU rate is one of three whole-house residential rates available to EV owners.[12] And while the rate is titled PEV-TOU, ownership of an EV is not a requirement of the rate. A further difference is that the CCN charging stations are fully capable of participating in Company demand response events to minimize any impact on system peak.

Q: Did the Staff make any recommendations regarding Plug-In Electric Rates?

A: Yes, Staff recommends that in addition to the reporting requirements discussed previously, that the Commission require consistency among the IOUs in the state with the implementation of PEV–TOU rates. Staff further states that the rate is needed to distinguish typical TOU rates with a rate specific to private home and business charging stations.[13]

Q: Do you agree with Staff's recommendation that all IOUs implement PEV-TOU rates?

A: I agree that a PEV-TOU rate represents a plausible approach to incent EV drivers to charge their vehicles during off-peak times the issue; I do not agree that the Company is ready to pursue a rate at this time. The Company shares Staff's desire to provide incentives for EV owners to manage their charging needs for the best utilization of

[11] *See Staff Report- Responding to Certain Commission Questions,* Case No. ER-2016-0285, Pp.6
[12] *https://www.georgiapower.com/about-energy/electric-vehicles/what-rate-plan-is-best-for-you.cshtml*
[13] *See Staff Report- Responding to Certain Commission Questions,* Case No. ER-2016-0285, Pp.7

electrical grid resources, but I am concerned that a requirement to implement a PEV-TOU rate is premature.

Q: Why is it premature?

A: Multiple studies are underway within the KCP&L and GMO companies to explore dynamic rates and demand side efforts. PEV-TOU rates for stand-alone charging stations and PEV-TOU rates applicable to EV charging associated with an existing account are specifically included in these studies Company witness Marisol Miller addresses these studies in her response to the Commission question regarding Residential TOU and TOD rate designs. As these studies have not been completed, it is unclear what the proper rate option should be made available for residential and commercial customers.

VI. RATE CASE EXPENSE

Q: What rate case expense issues will you address?

A: Staff witness Matthew R. Young and OPC witness Amanda C. Conner address in their responsive testimonies that rate case expense should be proportionally allocated to customers and shareholders based on the percentage of rate increase to the overall request.

Q: What is the Company's position regarding the treatment of rate case expense in this proceeding?

A: The cost of processing a rate case is a normal and essential cost of business of any public utility. As the Commission acknowledged in its Order in the investigatory docket on rate case expense treatment (Case No. AW-2011-0330), the Commission's "current rules and practice" are such that "regulated utilities generally recover all costs they incur in presenting a rate case before the Commission." More precisely, regulated utilities have generally recovered in rates reasonable and prudently incurred expenses that they incur in presenting rate cases to the Commission for resolution. Often, the reasonable and prudently incurred rate case expenses have been converted to an annualized level to be recovered over a number of years and included in base rates without a tracker mechanism recognizing that rate cases are not filed annually. The Company believes that this approach to rate case expense should be utilized in this case.

Q: Are Staff and OPC recommending a departure from the Commission's historical approach of allowing the recovery of reasonable and prudently incurred rate case expenses in rates?

A: Yes. Both Staff witness Matthew R. Young and OPC witness Amanda C. Conner recommend the formula used by the Commission in the KCP&L recent rate case, Case No. ER-2014-0370. By using this formula, the Staff and OPC may recommend a substantial disallowance in the Company's rate case expenses if in this case the Commission were to order an amount which is less than what the Company requested without any evidence (or even so much as an allegation) of imprudence by the Company.

Q: Why is Staff advocating that a portion of rate case expense be disallowed in this case?

A: Staff lists four reasons on page 127 of its Report. Those 4 reasons:

1.) This sharing mechanism was ordered by the Commission in the recent KCPL rate case, Case No. ER-2014-0370;

2.) Rate case expense sharing creates an incentive, and eliminates a disincentive, on the utility's part to control rate case expense to reasonable levels;

3.) There is a high likelihood that some positions advocated for by utilities through the rate case process will ultimately be found by the Commission to not be in the public interest; and

4.) Both ratepayers and shareholders benefit from the rate case process; the ratepayer receiving safe and adequate service at just and reasonable rates, and the shareholder receiving an opportunity to receive and adequate return on investment.

Q: Do you agree with the four reasons presented by Staff as the basis for a disallowance of a portion of the reasonable and prudently incurred rate case expenses in this case?

A: No. As the Staff Report points out, customers benefit from a rate case process that determines the just and reasonable rates that are to be paid for safe, adequate, and reliable service. Shareholders also benefit from a rate case process that gives the company a meaningful opportunity to earn a reasonable return on shareholders' investments in plant dedicated to the public use. Under the current regulatory system, the only manner in which these objectives may be accomplished is through the rate case process which is mandated by law. Rate case expenses are no different from other costs that provide benefits to customers (i.e. generation, transmission and delivery costs) because both shareholders and customers benefit from the company's continued operation. Simply put, periodic rate increases are necessary and provide a benefit to the customer by keeping the public utility financially healthy and in a position to provide the customers with safe and adequate service at just and reasonable rates. The customer is the primary beneficiary when a utility is able to fulfill its statutory obligation to provide safe, adequate and reliable service. This fundamental objective can only be accomplished if the company is able to attract investment by providing a reasonable return to its shareholders. As has been addressed throughout this case, rate cases and the regulatory mechanisms approved in rate cases are necessary and essential if the Company is to be in a position to adequately attract capital and have a reasonable opportunity to earn its authorized rate of return. It would make no sense to automatically disallow – in the absence of any evidence or allegation of imprudence – any of the other costs which benefit both the shareholder and the customer. For example, shareholders benefit from the construction of new power plants because the construction generally increases the shareholders' earnings levels, while customers benefit from the additional capacity used to serve them. Following the logic of Staff and OPC, a portion of those power plant costs would be disallowed since both the shareholders and customers benefit from those costs. Such a regulatory practice with power plant costs would quickly drive the public utility into dire financial straits, and adversely impact its ability to provide safe and adequate service to its customers. Finally, under long-standing regulatory precedent, shareholders are expected to have a reasonable opportunity to earn returns authorized by the Commission. An arbitrary disallowance of rate case expenses (i.e., charging shareholders for the regulatory costs to in fact establish rates that are to provide them that reasonable opportunity) is indeed an ironic and perverse start in providing the shareholders the opportunity that they are supposed to be afforded.

Q: The Staff Report asserts at p. 123 that "Generally, utility management has a high degree of control over rate case expense." Do you agree with this statement?

A: I agree that management has some discretion in how it presents its rate case, but it is also important to remember that the burden of proof is on the company in rate cases. It is also true that much of the rate case expenses are driven by the quantity and complexity of the issues that are raised by other parties to the case. The complexity and number of issues raised by other parties often drives the need to utilize outside consultants and outside counsel. While we hope to settle many of the issues raised by the parties before the hearing, the Company believes it needs to be prepared to try the issues raised by other parties in the event a settlement is not possible. These cases also typically involve massive amounts of discovery that are issued by Staff, OPC and numerous intervenors.

Q: Are there Commission regulations that contribute to the level of rate case expense that are beyond the control of a utility?

A: Yes. For example, a utility, like KCP&L is required to file a rate case with the effective date of new rates no later than four years in order to continue to utilize an FAC.2 In addition, 4 CSR 20.090 (9) requires a line loss study be conducted no less than every four years to be used in a general rate proceeding necessary to continue a FAC. The Commission has promulgated regulations that require the Company to periodically perform depreciation studies, and explain the Company's rate requests in detail. While the Company believes these may be appropriate regulations, it is apparent that such requirements will inevitably add to the cost of processing rate cases.

Q: Do you believe that the proposed allocation creates an incentive, and eliminates a disincentive, on the utility's part to control rate case expense to reasonable levels?

A: No. An arbitrary disallowance using a formula of dividing the revenue requirement ordered versus the amount requested and multiplying this by the reasonable and prudently-incurred rate case expense does not create an incentive to control rate case expenses. This approach merely makes it more difficult for the Company to earn its authorized rate of return. It is appropriate and reasonable for the Commission to review rate case expenses as to reasonableness and prudence. The Commission has disallowed rate case expense costs in the past on grounds of imprudence, and this serves as ample incentive for the Company to make certain that its rate case expenses are reasonable. However, an arbitrary disallowance of a portion of all prudently incurred rate case expenses is not reasonable or good public policy, and appears instead to serve as an incentive for Staff and parties to forego audit and review of rate case expenses.

Q: Does the approach advocated by Staff and OPC raise other concerns?

A: Yes. A fundamental problem with an arbitrary disallowance of prudently incurred rate case expense is that it effectively restricts the Company's ability and right to direct the presentation of its case, and to choose its legal and regulatory strategy before the Commission in rate case litigation that is required to obtain adequate rate levels. In the past, the Commission has recognized a public utility's right to make these decisions as long as its costs are prudently incurred: "The Commission is hesitant to disallow expenses incurred by MGE in prosecuting its rate case. The company is entitled to present its case as it sees fit and the Commission will not lightly intrude into the Company's decision about how best to present its case."[14]

Q: Does KCP&L have an incentive to control its rate case expenses?

A: Yes. We strive to balance cost control measures with providing the best level of service possible. Rate case expense is a normal part of doing business within a regulated system. Attached as Schedule TMR-10 is a flowchart which depicts the process the Company utilizes to manage rate case expense. This process helps ensure the monitoring and control of those costs. Like other expenses necessary to provide service to customers, the Company strives to be as efficient as possible in the presentation of its case while attempting to clearly explain its position on the issues to the Commission. The Company would fully expect that its rate case expenditures will be carefully and thoroughly reviewed by the Staff and other parties to determine their reasonableness and prudence, unless of course they are allowed to blindly apply the arbitrary ER-2014-0370 formula in lieu of performing such work. In addition, the Company does not recover its rate case expenses on a dollar for dollar basis under the traditional method of handling rate case expenses. Often, the rate case expenses are amortized or normalized over a greater number of years than the period between rate cases. For example, in Case No. ER-2014-0370, rate case expense was normalized over three years, but KCP&L filed this rate case less than twelve months after the rates from Case No. ER-2014-0370 took effect. As a result, the normalizations/amortizations are sometimes prematurely terminated before all prudently incurred rate case expenses are actually recovered. The Company has an

[14] Report And Order, *Re Missouri Gas Energy*, Case No. GR-2004-0209, p. 75.

incentive to be efficient in the presentation of its rate cases as well as with the purchase of other services necessary to provide safe and adequate electric service to our customers.

Q: **Staff has recommended that rate case expenses in this case be amortized over three years, and that no tracker be established. They indicate that this has been past practice except for the time that the CEP was in place. How do you respond?**

A: While our goal is to minimize the frequency of future general rate case filings, our ability to do so depends significantly on the outcome of this proceeding. I recommend that rate case expenses from this case be treated as a deferral and amortized over a three year period. In this way, a Regulatory Asset can be established and tracked based on the Stipulation and Agreement in Case No. ER-2014-0370. Also, both Company and ratepayers will be protected that full recovery of rate case expenses will be recovered by the Company and ratepayers will only pay for the those expenses that the Commission authorized in this case.

Q: **The Staff Report at p. 125 analogizes rate case expenses to discretionary expenses such as charitable contributions and lobbying expenses. Do you agree with these analogies?**

A: No, unlike charitable contributions and lobbying expenses, rate case expenses are not discretionary. If the Company's cost of service has increased, it is necessary for the Company to file a rate case in order to adjust the rates to reflect its ongoing cost of service. In fact, KCP&L is required by Commission regulation to periodically file rate cases if it is to continue to utilize the FAC. The same is required by Commission rule if a utility makes use of a demand side investment mechanism. While the Company could have arguably reduced (or eliminated) its charitable contributions and lobbying expenses, the Company is required to file a rate case under the Commission's FAC regulations to maintain its ability to use the FAC.

VII. AMI OPT-OUT RECOMMENDATION

Q: Staff witness Dan I. Beck made a recommendation for KCP&L to offer a meter op-out program consistent with the opt-out program at GMO, which would allow customers the option of a manually read meter rather than an AMI meter. How do you respond?

A: In the prior GMO rate case, GMO agreed to an opt-out residential tariff provision. KCP&L is not opposed to implementing a similar residential tariff with similar rates to recover manual read costs.

Q: Did Mr. Beck recommend anything else?

A: Yes. He further recommends that KCP&L keep track of the costs associated with the meter opt-out program in order to have cost data in KCP&L's next rate case to evaluate the one-time setup charge and recurring monthly meter read charge. The Company does not currently have any customers who have opted out of the AMI program. We have completed installation of all planned AMI meters. While we will keep track and report to the Commission in the next rate case on these costs, I simply want the Commission to be aware that we may not have any customers participate. The Commission should also be aware that a manual read will impact five different departments as there are many other costs other than the reading of the meter itself. These costs will be manually monitored as long as the customer has a non-standard meter.

Q: Does that conclude your testimony?

A: Yes, it does.

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-2016-0285

AFFIDAVIT OF TIM M. RUSH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Tim M. Rush, being first duly sworn on his oath, states:

1. My name is Tim M. Rush. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Kansas City Power & Light Company consisting of sixty-five (65) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Tim M. Rush

Tim M. Rush

Subscribed and sworn before me this 30th day of December, 2016.

Nicole A. Wehry

Notary Public

My commission expires: Feb. 4 2019

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2019
Commission Number: 14391200

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism	))))	File No. EO-2015-0240
In the Matter of KCP&L Greater Missouri Operations Company's Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism	))))	File No. EO-2015-0241

NON-UNANIMOUS STIPULATION AND AGREEMENT RESOLVING MEEIA FILINGS

COME NOW Missouri Public Service Commission Staff ("Staff"), Kansas City Power & Light Company ("KCP&L"), KCP&L Greater Missouri Operations Company ("GMO") (hereafter KCP&L and GMO are referred to collectively as the "Company"), the Office of the Public Counsel, National Housing Trust, West Side Housing Organization, Natural Resources Defense Council, Earth Island Institute d/b/a Renew Missouri, Missouri Department of Economic Development – Division of Energy and United for Missouri, Inc. (together, the "Signatories") and present this Non-Unanimous[1] Stipulation and Agreement ("Stipulation") to the Missouri Public Service Commission ("Commission") for the Commission's approval, and in support thereof respectfully state as follows:

I. BACKGROUND

1. On August 28, 2015, KCP&L filed in Case No. EO-2015-0240 and GMO filed in Case No. EO-2015-0241 separate applications ("Application") under the Missouri Energy Efficiency Investment Act ("MEEIA") and the Commission's MEEIA rules, along with their separate reports with appendices (HC and NP), requesting Commission approval of demand-side

[1] Without taking any position regarding the propriety of its terms, Missouri Industrial Energy Consumers have indicated they will not oppose this Stipulation.

programs and technical resource manual ("TRM")[2] and for authority to establish a demand-side programs investment mechanism ("DSIM").

II. SPECIFIC TERMS AND CONDITIONS

2. Complete Settlement of Case. As a result of extensive settlement discussions among all of the Signatories, the Signatories have agreed upon the terms[3] and conditions set forth below in full and final resolution of all issues in this case. This Stipulation is solely the result of compromise in the settlement process and does not serve as precedent beyond this Stipulation.

3. Approval of Plan. The Signatories agree for purposes of this Stipulation, the Commission should grant approval for KCP&L and GMO ("KCP&L/GMO") to each implement demand-side programs ("MEEIA Programs") and the DSIM described in this Stipulation (the "Plan"). While there is disagreement among the Signatories on how the Plan's costs and benefits should be determined, the Signatories agree that the Plan is expected to provide benefits to all customers, including customers who do not participate in programs. While there is disagreement among the Signatories on the necessity of retrospective evaluation, measurement and verification ("EM&V"), under the specific circumstances of this Stipulation, the Signatories agree that the DSIM reasonably relies on retrospective EM&V when determining actual throughput disincentive and earnings opportunity amounts. Under the specific circumstances of the Stipulation, the Signatories agree that earnings opportunity ("EO") amounts as set forth in Appendix B are reasonably related to the impact that the MEEIA Programs are expected to have upon supply-side resource needs.

[2] TRM attached as Appendix I.

[3] Unless specifically defined herein, the terms used in the Stipulation are defined in the Commission's rules, 4 CSR 240-20.093(1) and 4 CSR 240-20.094(1).

4. MEEIA Programs and MEEIA Programs' Cost.

a. The MEEIA Programs are:

(i) Non-Residential/Business Programs: Business Energy Efficiency Rebate-Custom; Business Energy Efficiency Rebate-Standard; Strategic Energy Management; Block Bidding; Online Business Energy Audit; Small Business Direct Install; Business Programmable Thermostat; Demand Response Incentive;

(ii) Residential Programs: Income-Eligible Weatherization (this is a GMO-only program and will be available only for 2016); Home Lighting Rebate; Home Appliance Recycling Rebate; Income-Eligible Home Energy Report (this is a KCP&L program only); Home Energy Report; Online Home Energy Audit; Whole House Efficiency; Income-Eligible Multi-Family; Residential Programmable Thermostat; and

(iii) A research and pilot program also has been included consistent with the KCP&L/GMO applications filed on August 28, 2015 at page 51 (KCP&L) and page 56 (GMO).

b. The Company agrees to make its best effort to begin implementation of the MEEIA Programs on January 1, 2016, or on the effective date of the tariff sheets for the MEEIA Programs, if the effective date is other than January 1, 2016. The Plan period will conclude 36 months following initial implementation of the Plan. The KCP&L Plan includes a total budget of $50,436,843 for its MEEIA Programs. The GMO Plan includes a total budget of $52,640,451 for its MEEIA Programs. The budgets and annual energy and demand savings targets for each MEEIA Program are found in Appendix A.

c. KCP&L/GMO's Demand Response Incentive program customer incentive budget is based on customer incentive levels for any new or renewal contracts. The incentive levels for the program are contained in HC Appendix C. KCP&L/GMO will re-evaluate initial customer incentive payments with the ability to adjust the incentive payments during the Plan period. New or renewal contracts will have a maximum term of three years. The tariff sheet for the Demand Response Incentive program shall be modified as included in Appendix D.

d. No CFLs will be included in the Home Lighting Rebate Program. The Home Lighting Rebate Program will only include LEDs. KCP&L/GMO agree not to provide more than 120,000 CFL bulbs per company in 2016, 100,000 CFL bulbs per company in 2017 and 80,000 CFL bulbs per company in 2018 to food banks or similar outlets, which shall be evaluated as part of the Income-Eligible Multi-family program.

e. The Signatories agree that the Company shall promote the Missouri Home Energy Certification program in conjunction with its energy efficiency programs, and will promote it on the Company's website. The promotions shall be designed to highlight the program's ability to increase the marketability of homes that have been improved through energy efficiency investments. Any and all assertions of increased marketability shall comport with any and all other applicable laws.

f. The Signatories agree that Combined Heat and Power ("CHP") can qualify under the business custom program. Consistent with KCP&L/GMO's applications, CHP projects will be reviewed and approved on a case-by-case basis and approval is based upon available program funding. Approval of CHP projects is solely at KCP&L/GMO's discretion.

5. <u>Special Provisions for Income-Eligible Multi-Family ("IEMF")</u>.

a. KCP&L/GMO will provide owners of multi-family buildings with a single point of contact ("Coordinator") for in-unit and common area/building system measures (regardless of whether the impact is to a residential or commercial customer). The Coordinator's duties will include:

(i) Determining eligibility and ensuring eligible customers are aware of the available incentives from all utilities.

(ii) Assisting in the application process for KCP&L/GMO residential and business improvements.

(iii) Providing a seamless point of contact for navigating the various incentive offers provided by the Company.

(iv) Maintaining a relationship with the existing business trade ally network and providing information and guidance to assist the incentive applicant with the bid process for installation work.

(v) Understanding and maintaining a network of assistance agencies and making referrals for financing and repairs, seeking to remove barriers to participation.

(vi) Providing case studies and education, and working with business development teams to ensure proper outreach is occurring.

(vii) Creating marketing materials to provide an easy to understand process for participation.

(viii) Engaging with other utilities where synergies in marketing and delivery of programs can be gained.

(ix) Maintaining working relationships with and providing outreach and education to stakeholders such as lenders, Missouri agencies, and other identified parties.

b. For the purposes of this program, a building's eligibility will be determined by the income qualification of the tenant occupants, who must meet one of the following requirements for eligibility:

(i) Reside in federally-subsidized housing units and fall within that program's income guidelines. State Low-Income Housing Tax Credit buildings will be eligible only to the extent allowed under state law.

(ii) Reside in non-subsidized housing with an income at 200% of poverty level or below. Where a property has a combination of qualifying tenants and non-qualifying tenants, at least 51% of the tenants must be eligible to receive incentives for the entire building to qualify. For IEMF properties with less than 51% qualifying tenants, the owner/manager will be required to verify installation of comparable qualified energy efficiency measures at their own expense in all non-qualifying units, then the program may upgrade the whole building, common areas and all of the eligible units with qualified energy efficiency measures.

c. Multi-family buildings (as defined to be including three or more units) with service under the KCP&L/GMO Service Classification of Residential or Non-Residential (excluding lighting classifications) will be eligible to participate in this program as long as the buildings meet the eligibility requirements above.

d. The program will provide a custom rebate option for comprehensive retrofits and measures to IEMF property owners for IEMF whole building and non-lighting common area measures, as well as for in-unit measures not otherwise covered as direct-install measures under KCP&L/GMO's IEMF program. The following measures are indicative of what will be available for the whole building and common areas: heating, ventilation and air conditioning; domestic hot water; motors; envelope improvements; controls and EMS; and pump/fan/piping/duct improvements. Common area lighting retrofits will be included as prescriptive measures. Custom incentives provided to income-eligible multifamily buildings will be provided at a $0.02 per kWh premium over Business Custom incentives.

e. Level 1 energy audits with information on savings, estimated cost, and typical payback range and aggregated whole-building electricity usage data will be offered to qualifying buildings at no cost. The Company shall develop a list of recommended measures that will provide savings for the building and provide information on available prescriptive and performance-based (e.g. business custom) incentives. Restrictions on the frequency of aggregated whole-building electricity usage data reports may be established by KCP&L/GMO. The cost to KCP&L/GMO to provide aggregated whole-building electricity usage data is considered a program cost. It is understood that the aggregated whole-building electricity usage data made available to owners (or their authorized agents) shall not provide data identifiable to any specific KCP&L/GMO customer in the building.

6. <u>Identification of Additional Energy Savings</u>.

a. KCP&L/GMO is performing a potential study which is expected to be completed during 2017. As a separate initiative, KCP&L/GMO agree to a collaborative process with Signatories, to address new, unserved, or underserved customer markets and identify cost-effective energy and demand savings strategies (a possible additional 200 GWh of savings) that could be considered for implementation for program years 2017 and 2018 if all customers within the customer class realize a benefit. The possible additional 200 GWh is neither a floor nor a cap. Although there may be disagreement among the Signatories to the Stipulation about whether or how easily additional savings could be achieved, the Signatories agree to work together to identify strategies to maximize savings in a cost effective manner and to determine the feasibility of implementing additional programs or savings. Cost effective strategies to be assessed will include, but are not limited to: expanding upstream programs to include additional lighting, HVAC and consumer electronics; using whole building benchmarking as a tool to prioritize existing buildings over 50,000 square feet for delivery of a streamlined bundle of energy efficiency services (including retro-commissioning); refining target markets so as to reduce the potential for free riders; evaluating and re-evaluating incentive payment levels with a view to modifying them if appropriate; evaluating charging participants for program services at just and reasonable rates to be approved by the Commission; evaluating earnings opportunity in relationship to participant payments; using a single point of contact to increase participation rates and reduce customer acquisition costs; working with large employers in the service territory to market energy efficiency services to their employees; assistance with whole building deep energy savings for new construction and existing buildings; whole home approaches for new and existing homes, and co-delivery with gas utilities. The Signatories also agree to consider low-income approaches not already addressed in the multifamily program, which need not pass a cost effectiveness test, but should be implemented in a prudent manner. The Signatories agree to have these discussions between the fourth and sixth month after the effective date of the tariff sheets implementing MEEIA Cycle 2. The Signatories agree that the Company will develop and file in both dockets a report summarizing the collaborative discussions described above. The cost to the Company of the collaborative process and associated report will be recovered through the DSIM as part of the budget for Research & Pilot program.

b. The Company must seek and receive Commission approval prior to adding any new programs identified in the collaborative process. If Commission-approved new programs are added in years 2017 and 2018, the Company may seek Commission approval to have the targets for the utility cap and the total cap as referenced in Appendix B of the EO matrix scale proportionately to the increase in annual energy and demand savings targets. Any programs that are added will be added in accordance with the Commission's rule 4 CSR 240-20.094(4).

7. Energy and Demand Savings. The Plan has the following planned energy and demand savings:

36 Month Plan Period	Planned Energy Savings (kWh)	Planned Demand Savings (kW)
GMO	184,549,652	105,855
KCP&L	198,097,872	66,328

The energy and demand savings targets for each of the individual MEEIA Programs are included in Appendix A and in the program tariff sheets attached as Appendix D.

The total resource cost test ("TRC") for the portfolio of MEEIA Programs is 1.68 and 1.81 for KCP&L and GMO, respectively. The TRCs and other cost effectiveness ratios for individual MEEIA Programs are included in Appendix E.

8. Evaluation Measurement and Verification ("EM&V").

a. KCP&L and GMO agree to perform an annual EM&V process and impact evaluations, which will include both an ex-post gross and a net to gross ("NTG") evaluation. NTG ratio equals 1 minus Free Ridership Rate plus Participant Spillover Rate plus Non-Participant Spillover Rate. Net Savings equals NTG Ratio times ex post gross savings. The EM&V plan and guidelines are attached in Appendix F.

(i) Annual ex-post gross by measure will be used to adjust the TRM annual kWh/kW. Throughput Disincentive ("TD") will utilize the updated TRM on a prospective basis.

(ii) Program Plan Years 1 and 2 EM&V NTG will be utilized for planning purposes for Cycle 3 to the extent available.

(iii) The final EM&V in the program period will include a Cycle 2 NTG as determined by the Evaluator, reviewed by the Commission's Auditor, and approved by the Commission.

b. KCP&L and GMO agree to provide stakeholders the EM&V evaluator request for proposal for review and comment prior to release.

c. KCP&L and GMO agree to increase the budget up to a 6% level of the Commission-approved[4] program costs budget for the EM&V. This increase has been reflected in Appendix A.

9. DSIM. The Signatories agree to the DSIM described in this Stipulation and attached as tariff sheets in Appendix D. To the extent this Section 9 differs from tariff sheets, the tariff sheets govern.

a. The DSIM addresses recovery of KCP&L/GMO's MEEIA Programs' costs, KCP&L/GMO's TD that is intended to recover lost margin revenues, and any earned EO Award. The Company will begin recovery through a DSIM Rider beginning at the implementation of the Plan billing or as soon as practical thereafter. See Appendix G for an example of the TD calculation and the EO adjustments for TD. Program costs and TD will be recovered contemporaneously. Program costs and TD will begin recovery upon approval by the Commission and will continue until all program costs and TD are recovered.

Program Costs: The Plan includes MEEIA Programs cost of $50,436,843 and $52,640,451, respectively for KCP&L and GMO, which are based on the planned budgets for the MEEIA Programs to be delivered over the 36-month period following effective date of the tariff sheets. If Commission-approved new programs are added in years 2017 and 2018, program costs will also be included.

Throughput Disincentive: The kWh savings will be reflected in the TD by multiplying the kWh savings for each program for the respective month times the incremental rate for the respective class[5]. A NTG initial factor of 0.85 will be used for contemporaneous TD recovery. Annual kWh savings per measure will be updated prospectively in KCP&L/GMO's TRM no

[4] The Signatories expressly acknowledge that the provisions of 4 CSR 240-20.094(4) govern the process to be used in the event MEEIA cycle 2 program costs exceed budgeted levels of 20% or more.

[5] The loadshapes for the programs are attached as Appendix J.

later than 24 months after the commencement of the Plan based on EM&V ex-post gross adjustments determined for Year 1.

Earnings Opportunity Award:

a. KCP&L and GMO will perform a full EM&V including an ex post gross adjustment and NTG determination for EO with no NTG floor and no NTG cap. For purposes of the EO, the kWh and kW savings measurements will be determined through the annual EM&V including NTG with no floor or cap on the NTG factor, based on actual measures installed in that year annualized unless otherwise described in the EO matrix (Appendix B). The EO awarded will be adjusted as follows:

(i) **TD Ex Post Gross Adjustment** – At the end of the three-year cycle, the annual ex-post gross measures for each program determined through the annual EM&V will be used to recalculate the TD as described above for each of the annual evaluation periods. The difference between the recalculated TD using ex-post gross measures and the TD using the deemed numbers, whether an increase or a decrease will be adjusted in the EO by applying carrying costs at the AFUDC rate compounded semi-annually.

(ii) **TD NTG Adjustment** – At the end of the three-year cycle, if the portfolio EM&V NTG is greater or less than the initial factor of 0.85, the difference between TD at 0.85 NTG and the TD calculated using the EM&V NTG, subject to a NTG cap of 1.00 and a floor of 0.80, will be recovered through the EO, including carrying costs at the AFUDC rate compounded semi-annually.

b. The Signatories agree that the EO cannot go below zero. The EO target at 100% is $7,429,296 million for KCP&L and $10,383,855 for GMO. For KCP&L, the EO (before adjustments reflecting TD EM&V including NTG) cannot go above $10,495,620. For GMO, the

EO (before adjustments reflecting TD EM&V including NTG) cannot go above $14,290,195. For KCP&L, the EO (including adjustments reflecting TD EM&V including NTG) cannot go above $15,500,000. For GMO, the EO (including adjustments reflecting TD EM&V including NTG) cannot go above $20,000,000. The caps are based on the current program levels. If Commission-approved new programs are added in years 2017 and 2018, the Company may seek Commission approval to have the targets for the cap of the EO scale proportionately to the increase in savings targets.

(i) **Allocation of Program Costs, TD and EO:** In general, MEEIA programs are designated as either Residential or Non-Residential (Business) and will be recovered by Residential or Non-Residential customer classes, respectively. Commission-approved Program costs, TD and EO relating to the IEMF Program, Income-Eligible Weatherization Program and Income-Eligible Home Energy Report Program will be allocated 50/50 to Residential and Non-Residential customer classes for recovery. The Research costs will be allocated appropriately to the customer classes. The Pilot program costs will be assigned appropriately to the customer classes to which the Pilot program is offered.

(ii) **Recovery Mechanism:** It is the intent of the Signatories that KCP&L and GMO ultimately shall bill customers for an amount as close as reasonably practicable to the actual MEEIA Programs' costs incurred, the TD, and any earned EO Award as provided for herein.

The initial DSIM Rider illustrative tariff sheets are attached as Appendix D and reflect the recovery of Commission-approved MEEIA Program costs, TD and EO Award, including interest. The rate to be charged to residential and non-residential classes initially will be determined by including the estimated initial six month Program costs and the TD plus the unrecovered balances from Cycle 1 MEEIA programs for KCP&L and one-fourth of the unrecovered balances from GMO (GMO unrecovered balances from Cycle 1 will be recovered over a 24 month period) as set out in the tariff sheets in Appendix D.

(iii) **Separate Item on the Bill:** Charges from the MEEIA Plan shall be reflected as "DSIM Charge" on a separate line item on customers' bills.

10. Annualizations. Upon filing a rate case, the cumulative, annualized, normalized kWh and kW savings will be included in the unit sales and sales revenues used in setting rates as of an appropriate time (most likely two months prior to the true-up date) where actual results are known prior to the true-up period, to reflect energy and demand savings in the billing determinants and sales revenues used in setting the revenue requirements and tariffed rates in the case. Upon the adjustment for kWh and kW savings in a rate case, the collection of TD will be re-based.

a. Test period weather normalized kWh usage for each customer class by billing month will be adjusted by[6]:

(i) Adding back the monthly kWh energy savings by customer class incurred during the test period from all active MEEIA programs, excluding Home Energy Reports and Income-Eligible Home Energy Reports programs which have a one year measure life, determined using the same methodology as described in Tariff Sheet 49K and 49L (KCP&L) and in Tariff Sheet 138.4 and 138.5 (GMO) except that calendar month load shape percentages by program by month will be converted to reflect billing month load shape percentages by program by computing a weighted average of the current and succeeding month percentages.

[6] Step 1. Begin with Weather Normalized kWh per class provided by Company. Step 2. Compute Monthly Savings kWh (MS) per program in the same manner as used for TD calculation. Step 3. Weather Normalized kWh before application of Energy Efficiency (EE) adjustment. Step 4. Cumulative Annual Savings kWh (CAS) per program computed in the same manner as TD calculation as of Rebase Date. Step 5. Monthly Load Shape percentage per program converted to billing month equivalent by using a weighted average calendar month Load Shape percentage based on billing cycle information of the rate case. Step 6. Monthly EE Rebase Adjustment. Step 7. Weather Normalized kWh rebased for EE.

b. The Adjusted test period sales from above will be annualized for customers and additionally be adjusted further by:

(i) Subtracting the cumulative annual kWh energy savings from the first month of the test period through the month ending where actual results are available (most likely two months prior to the true-up date) by customer class from all active MEEIA programs, excluding Home Energy Reports and Income-Eligible Home Energy Reports, determined using the same methodology as described in Tariff Sheet 49K and 49L (KCP&L) and in Tariff Sheet 138.4 and 138.5 (GMO) except that calendar month load shape percentages by program by month are converted to reflect billing month load shape percentages by program by computing a weighted average of the current and succeeding month percentages.

c. Test period kW demand for each customer class will be adjusted by[7]:

(i) Adding back the monthly kW demand savings by customer class incurred during the test period from all active MEEIA programs, excluding Home Energy Reports, Income-Eligible Home Energy Reports and Demand Response Incentive programs, determined using the same methodology as described for kWh savings in Tariff Sheet 49K and 49L (KCP&L) and in Tariff Sheet 138.4 and 138.5 (GMO) and then:

(ii) Subtracting the cumulative annual kW demand savings from the first month of the test period through the month ending where actual results are available (most likely two months prior to the true-up date) by customer class from all active MEEIA programs, excluding Home Energy Reports, Income-Eligible Home Energy Reports and Demand Response Incentive

[7] Step 1. Begin with kW demand per class provided by Company. Step 2. Compute Monthly kW demand per program in the same manner as used for TD calculation. Step 3. kW demand before application of Energy Efficiency (EE) adjustment. Step 4. Cumulative Annual kW demand per program computed in the same manner as TD calculation as of Rebase Date. Step 5. Monthly Load Shape percentage per program converted to billing month equivalent by using a weighted average calendar month Load Shape percentage based on billing cycle information of the rate case. Step 6. Monthly EE Rebase Adjustment. Step 7. kW demand rebased for EE.

programs, determined using the same methodology as described for kWh savings in Tariff Sheet 49K and 49L (KCP&L) and in Tariff Sheet 138.4 and 138.5 (GMO).

11. KCP&L/GMO shall each file a general rate case at some point before the end of year 5 of the Cycle 2 period to address the TD through the rebasing of revenues used to establish base rates, and if KCP&L/GMO fails to do so, the accrual and collection of the TD terminates beginning in year 6 of the Cycle 2 period. The Signatories agree that the filing of a rate case by each company utilizing an update or true-up period that ends between 30 months and 60 months after the effective date of the tariffs implementing MEEIA Cycle 2 satisfies this requirement.[8]

12. Transition Between MEEIA Cycles.

a. The last day to submit an application for the Cycle 1 C&I Custom Rebate program is December 15, 2015. The last day for approval of an application for the Cycle 1 C&I Custom Rebate program is January 31, 2016. The last day for completion of customer projects and submission of complete paperwork by customers is June 30, 2016. The final payment by KCP&L/GMO of rebates for all Cycle 1 projects is July 31, 2016.

b. KCP&L/GMO made a tariff filing, on November 12, 2015 to modify tariff sheets to reflect the agreement set forth in paragraph 12 a.

[8] For example, if the effective date of the tariffs implementing MEEIA Cycle 2 is January 1, 2016, then the filing of a rate case by each company with an update period ending within the period from July 1, 2018 through December 31, 2020 satisfies this requirement.

c. Cycle 1 EM&V calendar is:

Stipulation and Agreement in File Nos. EO-2012-0009 and EO-2014-0095

Stipulation Paragraph	Process Steps	Program Year Days	Cumulative Days	Date
10.b.i.	Draft EM&V Report Circulated to Stakeholders	120	120	4/30/16
10.b.ii.	Comments and Recommendations on Draft EM&V Report	60	180	6/29/16
10.b.iii.	Meeting to Discuss Comments Prior to Final Draft Report	0	180	6/29/16
10.b.iv.	Final Draft EM&V Report Issued	30	210	7/29/16
10.b.[first]iv.	Still Concerns – Comments on Final Draft Report	20	230	8/18/16
10.b.[first]iv.	Still Concerns – Conference Call to Attempt to Resolve Concerns	10	240	8/28/16
10.b.[first]iv.	Still Concerns – Final EM&V Report Issues	15	255	9/12/16
10.b[second]iv.	File a Change Request	21	276	
10.b[second]iv.	Conference Call on Procedural Schedule	2	278	
10.b[second]iv.	File Responses to Change Request	19	297	
10.b[second]iv.	Evidentiary Hearing Completed Not Later Than	39	336	
10.b[second]iv.	Commission Report and Order Not Later Than	30	366	

(i) The KCP&L/GMO Evaluator will include a section in its April 30, 2016 draft EM&V Report which will identify any C&I Custom Rebate projects which have been approved for Cycle 1, but which have not been included in the results of the April 30, 2016 draft EM&V Report ("Carryover Project").

(ii) The KCP&L/GMO Evaluator will include a separate section of its July 29, 2016 final EM&V Report which will:

- List the Carryover Projects;
- Provide the EM&V results for the Carryover Project for which EM&V is complete and identify each Carryover Project for which EM&V is incomplete ("Incomplete Carryover Project"); and
- State when it expects to have the final EM&V results for Incomplete Carryover Projects.

(iii) Stakeholders can express concerns and provide comments by August 18, 2016 regarding the July 29, 2016 final EM&V Report including any concerns and comments regarding Incomplete Carryover Projects.

d. Recovery of all Cycle 1 DSIM costs including all program costs, all throughput disincentive and any performance incentive for Cycle 1 C&I Custom Rebate program projects will be achieved through the Cycle 1 DSIM subject to prudence review for Cycle 1 DSIM costs. As the result of the agreements in this Stipulation, KCP&L and GMO shall use their respective Cycle 1 2015 DSMore files to calculate the Cycle 1 gross benefits to determine the TD-NSB for projects completed under the C&I Custom Rebate program between January 1, 2016 and June 30, 2016. These projects will be modeled in DSMore with a completion date of December 31, 2015. The Cycle 1 performance incentive amounts will result from full retrospective EM&V.

e. The Signatories acknowledge that by including C&I Custom Rebate carryover projects that were approved under Cycle 1 and those paid out through July 31, 2016 will increase the GMO/KCP&L MEEIA Cycle 1 actual expenditures above the Commission-approved budget. Moreover, additional EM&V costs may be incurred by GMO/KCP&L to accommodate these carryover projects, which will also impact the allowable 5% EM&V budget. The Signatories agree that if the additional EM&V costs are less than $100,000, Commission approval is not needed.

f. While the Stipulation does not include a specific transition plan for Cycle 2, the Signatories agree that such a plan will likely be needed for the Business Custom program or other programs with lead times longer than 30 days, whether or not there is a Cycle 3. Therefore, the Company will propose a transition plan to the Signatories at least one (1) year prior to the end of Cycle 2. The Signatories will use best efforts to agree on a transition plan at least nine (9) months prior to the end of Cycle 2. Any Cycle 2 transition plan will require application to and approval by the Commission in accordance with 4 CSR 240-20.094(4).

13. Regulatory Flexibility.

a. For the purposes of settlement of Case Nos EO-2015-0240 and EO-2015-0241 only, the Signatories recommend the Commission waive 4 CSR 240-20.094(5) for good cause in light of future uncertainties and in recognition of the fact that the offering of MEEIA programs is voluntary at the election of the electric utility (section 393.1075.4 RSMo. and 4 CSR 240-20.094(3)(E)). KCP&L/GMO will not commit to implement MEEIA Cycle 2 portfolio for a three-year period, without the ability to discontinue all programs in the MEEIA 2 portfolio under appropriate conditions as defined by KCP&L/GMO. Therefore, KCP&L/GMO's MEEIA Cycle 2 tariff sheets shall include a reservation of rights provision reading as follows:

> KCP&L/GMO reserves the right to discontinue the entire MEEIA Cycle 2 portfolio, if KCP&L/GMO determines that implementation of such programs is no longer reasonable due to changed factors or circumstances that have materially negatively impacted the economic viability of such programs as determined by KCP&L/GMO, upon no less than thirty days' notice to the Commission.

b. In the event of discontinuance, KCP&L/GMO shall provide notice in Case No. EO-2015-0240 and/or Case No. EO-2015-0241 no less than thirty (30) days prior to discontinuing the MEEIA Cycle 2 portfolio. KCP&L/GMO shall also provide written notice to the Signatories to this Agreement no less than thirty (30) days prior to the effective date of such discontinuance. KCP&L/GMO shall also advise customers of discontinuance by publication no less than thirty (30) days prior to the effective date of such discontinuance in newspaper(s) of general circulation in KCP&L/GMO service territory. KCP&L/GMO shall honor commitments made to MEEIA Cycle 2 program participants prior to the effective date of the discontinuance. In its notice, KCP&L/GMO shall (1) explain the reason(s) (e.g., changed circumstances) for the discontinuance of all MEEIA Cycle 2 programs in the portfolio); and (2) provide detailed workpapers that support its determination that continued implementation of the MEEIA Cycle 2 portfolio is unreasonable. Concurrent with its notice filing, KCP&L/GMO shall file a new tariff sheet(s) to indicate that the Company is no longer offering the MEEIA Cycle 2 portfolio.

c. In the event that KCP&L/GMO terminates all MEEIA Cycle 2 programs, KCP&L/GMO shall forfeit any recovery of the EO in connection with such programs but will continue to collect through the DSIM mechanism: (1) Program Costs incurred in delivering programs for commitments made by KCP&L/GMO to program participants prior to the effective date of the discontinuance and (2) Throughput Disincentive related to energy savings delivered through the discontinued MEEIA Cycle 2 programs through the date such savings have been "rebased" in a general rate case. The Company's independent evaluator will perform a final EM&V to be reviewed by the Commission's Auditor and approved by the Commission.

d. If any party has concerns regarding KCP&L's/GMO's discontinuance of all MEEIA Cycle 2 programs, it shall file a responsive pleading in Case No. EO-2015-0240 and/or Case No. EO-2015-0241 within fifteen (15) days of KCP&L/GMO's written notification. Upon receipt of any such response, KCP&L/GMO shall promptly schedule a meeting, (providing reasonable advance notice of the meeting to all Signatories) where KCP&L/GMO will attempt in good faith to answer all questions regarding the discontinuance of all MEEIA Cycle 2 programs. In the event the Commission has questions or concerns, KCP&L/GMO agree to appear at a hearing or Agenda to address those concerns.

e. In the event all programs of KCPL and/or GMO are discontinued, Staff will continue to schedule and perform prudence reviews of the costs subject to the KCP&L/GMO DSIM.

f. KCP&L/GMO will take action as soon as reasonably practicable to adjust rates consistent with the discontinuance of the portfolio to ensure that KCP&L/GMO neither over- nor under-recovers costs incurred in connection with KCP&L/GMO's MEEIA Cycle 2 portfolio. To the extent that KCP&L/GMO has over-recovered, such over-recoveries shall be returned to customers with interest at KCP&L/GMO's short-term borrowing rate. To the extent that KCP&L/GMO has under-recovered, such under-recoveries shall be recovered from customers with interest at KCP&L/GMO's short-term borrowing rate.

14. Rider.

a. Initial rates for Residential and Non-Residential will be computed for estimated initial six month Program Costs and the TD plus the unrecovered balances from Cycle 1 MEEIA programs for KCP&L (GMO unrecovered balances from Cycle 1 will be recovered over a 24 month period) as set out in the tariff sheets in Appendix D. Over- or Under- recovery of Commission-approved Program Costs and TD will be tracked and included in Rider adjustment for each six-month period thereafter for estimated Programs Costs and TD. EO will be computed in 2019 and included in Rider over a two-year period thereafter. The Cycle 1 Performance incentive will be collected through the Rider.

b. GMO will initiate a rider mechanism as shown on the specimen tariff sheets to take effect January 1, 2016 with rates effective February 1, 2016. GMO reserve balances for Cycle 1 will be recovered over a two year period and will be included in the initial tariffs and trued up through the tariff process.

c. KCP&L reserve balances for Cycle 1 will be recovered over a six-month period and will be included in the initial tariffs and trued up through the tariff process.

15. Building Information.

a. KCP&L agrees to provide upon request to owners (or their authorized agents) of multi-tenant buildings with five or more tenants and over 50,000 square feet, aggregated whole-building electricity usage data no later than January 1, 2017. Restrictions on the frequency of aggregated whole-building electricity usage data reports may be established by KCP&L/GMO. The cost to KCP&L/GMO to provide aggregated whole-building electricity usage data is considered a program cost for Business Energy Efficiency Rebate-Custom. It is understood that the aggregated whole-building electricity usage data made available to owners (a) shall be used solely for benchmarking purposes and (b) shall not provide data identifiable to any specific KCP&L/GMO customer in the building.

16. Other Items.

a. Customer Notice for Cycle 3 – KCP&L and GMO will provide customers a notification that the companies have filed for their next round of MEEIA programs. KCP&L and GMO will provide Staff and OPC with draft language for the customer notice prior to the MEEIA filing. KCP&L and GMO will review and consider suggested edits to the draft language from Staff and OPC prior to the filing. Distribution of this notice will begin once the filings have been made.

b. The Signatories agree that KCP&L does not need to make a December 1, 2015 DSIM rider tariff filing because the specimen tariff sheets set forth in Appendix D include the DSIM rider tariff (Sheet No. 49E) that KCP&L would file on December 1, 2015. The Signatories agree that if the Commission approves this Stipulation and orders the filing of compliance tariff sheets, Sheet No. 49E should take effect on February 1, 2016.

c. Variances. The Signatories agree that some of the terms and conditions in this Stipulation are inconsistent with the Commission's rules, and that good cause exists by the agreements made within this entire Stipulation to recommend the Commission grant

KCP&L/GMO variances from those rules.[9] The specific variances requested by the Company are found in Appendix H.

III. GENERAL PROVISIONS

17. This Stipulation is being entered into for the purpose of disposing of the issues that are specifically addressed herein. In presenting this Stipulation, none of the Signatories shall be deemed to have approved, accepted, agreed, consented or acquiesced to any ratemaking principle or procedural principle, including, without limitation, any method of cost or revenue determination or cost allocation or revenue related methodology, and none of the Signatories shall be prejudiced or bound in any manner by the terms of this Stipulation (whether it is approved or not) in this or any other proceeding, other than a proceeding limited to enforce the terms of this Stipulation, except as otherwise expressly specified herein. Without limiting the foregoing, it is agreed that this Stipulation does not serve as a precedent for future MEEIA plans, and does not preclude a party from arguing whether the Plan has or does not have an impact on KCP&L/GMO's business risk in any pending or future proceeding.

18. This Stipulation has resulted from extensive negotiations and the terms hereof are interdependent. If the Commission does not unconditionally approve this Stipulation, or approves it with modifications or conditions to which a party objects, then this Stipulation shall be void and no signatory shall be bound by any of its provisions.

19. If the Commission does not unconditionally approve this Stipulation without modification, or approves it with modifications or conditions to which a party objects, and notwithstanding its provision that it shall become void, neither this Stipulation, nor any matters associated with its consideration by the Commission, shall be considered or argued to be a waiver of the rights that any Signatory has for a decision in accordance with Section 536.080

[9] All rule references are to 4 CSR Division 240.

RSMo 2000 or Article V, Section 18 of the Missouri Constitution, and the Signatories shall retain all procedural and due process rights as fully as though this Stipulation had not been presented for approval, and any suggestions or memoranda, testimony or exhibits that have been offered or received in support of this Stipulation shall become privileged as reflecting the substantive content of settlement discussions and shall be stricken from and not be considered as part of the administrative or evidentiary record before the Commission for any further purpose whatsoever.

20. If the Commission unconditionally accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights (1) to call, examine and cross-examine witnesses pursuant to Section 536.070(2), RSMo 2000; (2) their respective rights to present oral argument and/or written briefs pursuant to Section 536.080.1, RSMo 2000; (3) their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and, (4) their respective rights to judicial review pursuant to Section 386.510, RSMo Supp. 2012. These waivers apply only to a Commission order respecting this Stipulation issued in this above-captioned proceeding, and do not apply to any matters raised in any prior or subsequent Commission proceeding, or any matters not explicitly addressed by this Stipulation.

21. This Stipulation contains the entire agreement of the Signatories concerning the issues addressed herein.

22. This Stipulation does not constitute a contract with the Commission. Acceptance of this Stipulation by the Commission shall not be deemed as constituting an agreement on the part of the Commission to forego the use of any discovery, investigative or other power which the Commission presently has. Thus, nothing in this Stipulation is intended to impinge or

restrict in any manner the exercise by the Commission of any statutory right, including the right to access information, or any statutory obligation.

23. The Signatories agree that this Stipulation resolves all issues raised in this case, and that the testimonies of all witnesses whose testimony was pre-filed in this case should be received into evidence without the necessity of the witnesses taking the witness stand.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been hand-delivered, transmitted by e-mail, or mailed, First Class, postage prepaid, this 23rd day of November, 2015, to counsel for all parties on the Commission's service list in this case.

/s/ Roger W. Steiner

Roger W. Steiner

MEEIA Progrmas for Cycle 1 and 2
Reduction in Energy and Revnues

RATE

RATE CLASS	January	February	March	April	May	June	July	August	September	October	November	December
RES	$0.08332	$0.08578	$0.08937	$0.09352	$0.09546	$0.12058	$0.12058	$0.12058	$0.12058	$0.08901	$0.09502	$0.08409
SGS	$0.08851	$0.08958	$0.09181	$0.09352	$0.09929	$0.13028	$0.12415	$0.12428	$0.12255	$0.09680	$0.09661	$0.08990
MGS	$0.05901	$0.05924	$0.06063	$0.06313	$0.06539	$0.09850	$0.09514	$0.09553	$0.09453	$0.06316	$0.06344	$0.05958
LGS	$0.04734	$0.04652	$0.04806	$0.05017	$0.05178	$0.07399	$0.07233	$0.07200	$0.07100	$0.05003	$0.04958	$0.04688
LPS	$0.03565	$0.03484	$0.03484	$0.03472	$0.03472	$0.03612	$0.03727	$0.03612	$0.03612	$0.03472	$0.03665	$0.03557

kWh
MEEIA Cycle 1
Net Adjustment - Summary by Customer Class

	January	February	March	April	May	June	July	August	September	October	November	December	
Residential	(1,342,571)	(1,050,452)	(826,592)	(660,358)	(553,502)	(634,256)	(728,331)	(607,159)	(373,087)	(239,676)	(148,557)	(46,887)	(7,211,429)
SGS	(581,167)	(559,744)	(576,761)	(584,097)	(629,564)	(750,852)	(830,586)	(830,362)	(698,974)	(518,026)	(392,996)	(342,591)	(7,295,719)
MGS	(2,201,811)	(2,132,619)	(2,185,427)	(2,203,065)	(2,368,756)	(2,808,029)	(3,115,214)	(3,186,878)	(2,731,335)	(2,022,105)	(1,544,951)	(1,377,555)	(27,877,745)
LGS	(3,205,744)	(3,111,180)	(3,211,520)	(3,225,640)	(3,452,015)	(4,093,913)	(4,507,479)	(4,641,220)	(4,024,933)	(3,019,253)	(2,347,945)	(2,071,116)	(40,911,958)
LPS	(1,601,821)	(1,571,715)	(1,630,751)	(1,551,816)	(1,567,081)	(1,918,603)	(2,222,359)	(2,155,997)	(1,745,127)	(878,054)	(292,837)	(229,520)	(17,365,682)
	(8,933,114)	(8,425,710)	(8,431,052)	(8,224,976)	(8,570,919)	(10,205,653)	(11,403,968)	(11,421,616)	(9,573,455)	(6,677,113)	(4,727,287)	(4,067,669)	(100,662,532)

kWh
MEEIA Cycle 2
Net Adjustment - Summary by Customer Class

	January	February	March	April	May	June	July	August	September	October	November	December	
Residential	(589,243)	(560,652)	(526,287)	(511,240)	(548,783)	(658,184)	(807,222)	(871,455)	(742,855)	(577,470)	(502,010)	(537,399)	(7,432,801)
SGS	(183,126)	(178,923)	(181,414)	(187,957)	(188,609)	(194,286)	(197,918)	(202,626)	(194,503)	(187,239)	(184,100)	(178,641)	(2,259,343)
MGS	(257,982)	(252,065)	(255,680)	(264,891)	(265,783)	(273,967)	(279,229)	(285,883)	(274,315)	(263,855)	(259,361)	(251,690)	(3,184,700)
LGS	(677,379)	(661,592)	(671,733)	(696,718)	(699,317)	(722,336)	(737,942)	(755,485)	(724,144)	(694,377)	(681,000)	(661,006)	(8,383,028)
LPS	(829)	(809)	(822)	(853)	(856)	(884)	(904)	(925)	(887)	(850)	(833)	(809)	(10,261)
	(1,708,558)	(1,654,041)	(1,635,937)	(1,661,658)	(1,703,348)	(1,849,657)	(2,023,215)	(2,116,374)	(1,936,704)	(1,723,792)	(1,627,304)	(1,629,545)	(21,270,133)
Total	**(10,641,672)**	**(10,079,751)**	**(10,066,989)**	**(9,886,635)**	**(10,274,266)**	**(12,055,311)**	**(13,427,184)**	**(13,537,990)**	**(11,510,160)**	**(8,400,905)**	**(6,354,591)**	**(5,697,213)**	**(121,932,666)**

MEEIA Cycle 1													
Residential	($111,862)	($90,110)	($73,869)	($61,760)	($52,837)	($76,480)	($87,823)	($73,212)	($44,987)	($21,333)	($14,116)	($3,943)	
SGS	($51,441)	($50,140)	($52,950)	($54,627)	($62,512)	($97,824)	($103,118)	($103,198)	($85,657)	($50,145)	($37,967)	($30,799)	
MGS	($129,927)	($126,329)	($132,499)	($139,090)	($154,888)	($276,591)	($296,392)	($304,431)	($258,197)	($127,711)	($98,019)	($82,079)	
LGS	($151,767)	($144,738)	($154,330)	($161,825)	($178,756)	($302,907)	($326,045)	($334,150)	($285,788)	($151,047)	($116,420)	($97,084)	
LPS	($57,112)	($54,760)	($56,817)	($53,872)	($54,402)	($69,299)	($82,817)	($77,873)	($63,033)	($30,482)	($10,733)	($8,164)	
Subtotal	($502,110)	($466,077)	($470,464)	($471,174)	($503,395)	($823,100)	($896,195)	($892,865)	($737,662)	($380,718)	($277,255)	($222,069)	($6,643,084)
MEEIA Cycle 2													
Residential	($49,095)	($48,094)	($47,032)	($47,813)	($52,386)	($79,365)	($97,336)	($105,081)	($89,575)	($51,399)	($47,701)	($45,192)	
SGS	($16,209)	($16,027)	($16,655)	($17,579)	($18,728)	($25,312)	($24,572)	($25,182)	($23,836)	($18,125)	($17,786)	($16,060)	
MGS	($15,223)	($14,931)	($15,501)	($16,724)	($17,379)	($26,986)	($26,567)	($27,309)	($25,931)	($16,664)	($16,455)	($14,997)	
LGS	($32,069)	($30,779)	($32,280)	($34,953)	($36,213)	($53,445)	($53,378)	($54,392)	($51,417)	($34,738)	($33,767)	($30,985)	
LPS	($30)	($28)	($29)	($30)	($30)	($32)	($34)	($33)	($32)	($30)	($31)	($29)	
Subtotal	($112,626)	($109,859)	($111,497)	($117,099)	($124,735)	($185,140)	($201,887)	($211,999)	($190,791)	($120,956)	($115,739)	($107,262)	($1,709,590)
Total	**($614,736)**	**($575,937)**	**($581,961)**	**($588,273)**	**($628,131)**	**($1,008,240)**	**($1,098,082)**	**($1,104,863)**	**($928,453)**	**($501,674)**	**($392,994)**	**($329,331)**	**($8,352,675)**

FERC Account Definitions

447 Sales for resale.
A. This account shall include the net billing for electricity supplied to other electric utilities or to public authorities for resale purposes.
B. Records shall be maintained so as to show the quantity of electricity sold and the revenue received from each customer.
NOTE: Revenues from electricity supplied to other public utilities for use by them and not for distribution, shall be included in account 442, Commercial and Industrial Sales, unless supplied under the same contract as and not readily separable from revenues includible in this account.

456.1 Revenues From Transmission of Electricity of Others.
This account shall include revenues from transmission of electricity of others over transmission facilities of the utility.

501 Fuel.
A. This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.
B. The cost of fuel shall be charged initially to account 151, Fuel Stock (for Nonmajor utilities, appropriate fuel accounts carried under account 154, Plant Materials and Operating Supplies) and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to account 152, Fuel Stock Expenses Undistributed (for Nonmajor utilities, an appropriate subaccount of account 154, Plant Materials and Operating Supplies). In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.
ITEMS
Labor:
1. Supervising purchasing and handling of fuel.
2. All routine fuel analyses.
3. Unloading from shipping facility and putting in storage.
4. Moving of fuel in storage and transferring fuel from one station to another.
5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler-house structure.
6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc.
Materials and Expenses:
7. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).
8. Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).
9. Cost of fuel including freight, switching, demurrage and other transportation charges.

10. Excise taxes, insurance, purchasing commissions and similar items.
11. Stores expenses to extent applicable to fuel.
12. Transportation and other expenses in moving fuel in storage.
13. Tools, lubricants and other supplies.
14. Operating supplies for mechanical equipment.
15. Residual disposal expenses less any proceeds from sale of residuals.

NOTE: Abnormal fuel handling expenses occasioned by emergency conditions shall be charged to expense as incurred.

509 Allowances.

This account shall include the cost of allowances expensed concurrent with the monthly emission of sulfur dioxide. (See General Instruction No. 21.)

518 Nuclear fuel expense (Major only).

A. This account shall be debited and account 120.5, Accumulated Provision for Amortization of Nuclear Fuel Assemblies, credited for the amortization of the net cost of nuclear fuel assemblies used in the production of energy. The net cost of nuclear fuel assemblies subject to amortization shall be the cost of nuclear fuel assemblies plus or less the expected net salvage of uranium, plutonium, and other byproducts and unburned fuel. The utility shall adopt the necessary procedures to assure that charges to this account are distributed according to the thermal energy produced in such periods.

B. This account shall also include the costs involved when fuel is leased.

C. This account shall also include the cost of other fuels, used for ancillary steam facilities, including superheat.

D. This account shall be debited or credited as appropriate for significant changes in the amounts estimated as the net salvage value of uranium, plutonium, and other byproducts contained in account 157, Nuclear Materials Held for Sale and the amount realized upon the final disposition of the materials. Significant declines in the estimated realizable value of items carried in account 157 may be recognized at the time of market price declines by charging this account and crediting account 157. When the declining change occurs while the fuel is recorded in account 120.3, Nuclear Fuel Assemblies in Reactor, the effect shall be amortized over the remaining life of the fuel.

547 Fuel.

This account shall include the cost delivered at the station (see account 151, Fuel Stock, for Major utilities, and account 154, Plant Materials and Operating Supplies, for Nonmajor utilities) of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation.

555 Purchased power.

A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

561.4 Scheduling, System Control and Dispatching Services.
This account shall include the costs billed to the transmission owner, load serving entity or generator for scheduling, system control and dispatching service. Include in this account service billings for system control to maintain the reliability of the transmission area in accordance with reliability standards, maintaining defined voltage profiles, and monitoring operations of the transmission facilities.

561.8 Reliability Planning and Standards Development Services
This account shall include the costs billed to the transmission owner, load serving entity, or generator for system planning of the interconnected bulk electric transmission system. Include also the costs billed by the regional transmission service provider for system reliability and resource planning to develop long-term strategies to meet customer demand and energy requirements. This account shall also include fees and expenses for outside services incurred by the regional transmission service provider and billed to the load serving entity, transmission owner or generator.

565 Transmission of electricity by others (Major only).
This account shall include amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others.

575.7 Market Administration, Monitoring and Compliance Services.
This account shall include the costs billed to the transmission owner, load serving entity or generator for market administration, monitoring and compliance services.

928 Regulatory commission expenses.
A. This account shall include all expenses (except pay of regular employees only incidentally engaged in such work) properly includible in utility operating expenses, incurred by the utility in connection with formal cases before regulatory commissions, or other regulatory bodies, or cases in which such a body is a party, including payments made to a regulatory commission for fees assessed against the utility for pay and expenses of such commission, its officers, agents, and employees, and also including payments made to the United States for the administration of the Federal Power Act.
B. Amounts of regulatory commission expenses which by approval or direction of the Commission are to be spread over future periods shall be charged to account 186, Miscellaneous Deferred Debits, and amortized by charges to this account.
C. The utility shall be prepared to show the cost of each formal case.
Items
1. Salaries, fees, retainers, and expenses of counsel, solicitors, attorneys, accountants, engineers, clerks, attendants, witnesses, and others engaged in the prosecution of, or defense against petitions or complaints presented to regulatory bodies, or in the valuation of property owned or used by the utility in connection with such cases.

2. Office supplies and expenses, payments to public service or other regulatory commissions, stationery and printing, traveling expenses, and other expenses incurred directly in connection with formal cases before regulatory commissions.
Note A: Exclude from this account and include in other appropriate operating expense accounts, expenses incurred in the improvement of service, additional inspection, or rendering reports, which are made necessary by the rules and regulations, or orders, of regulatory bodies.
Note B: Do not include in this account amounts includible in account 302, Franchises and Consents, account 181, Unamortized Debt Expense, or account 214, Capital Stock Expense.

Copied from the Federal Energy Regulatory Commission Electronic Code of Federal Regulations Title 18, Chapter 1, Subchapter C, Part 101

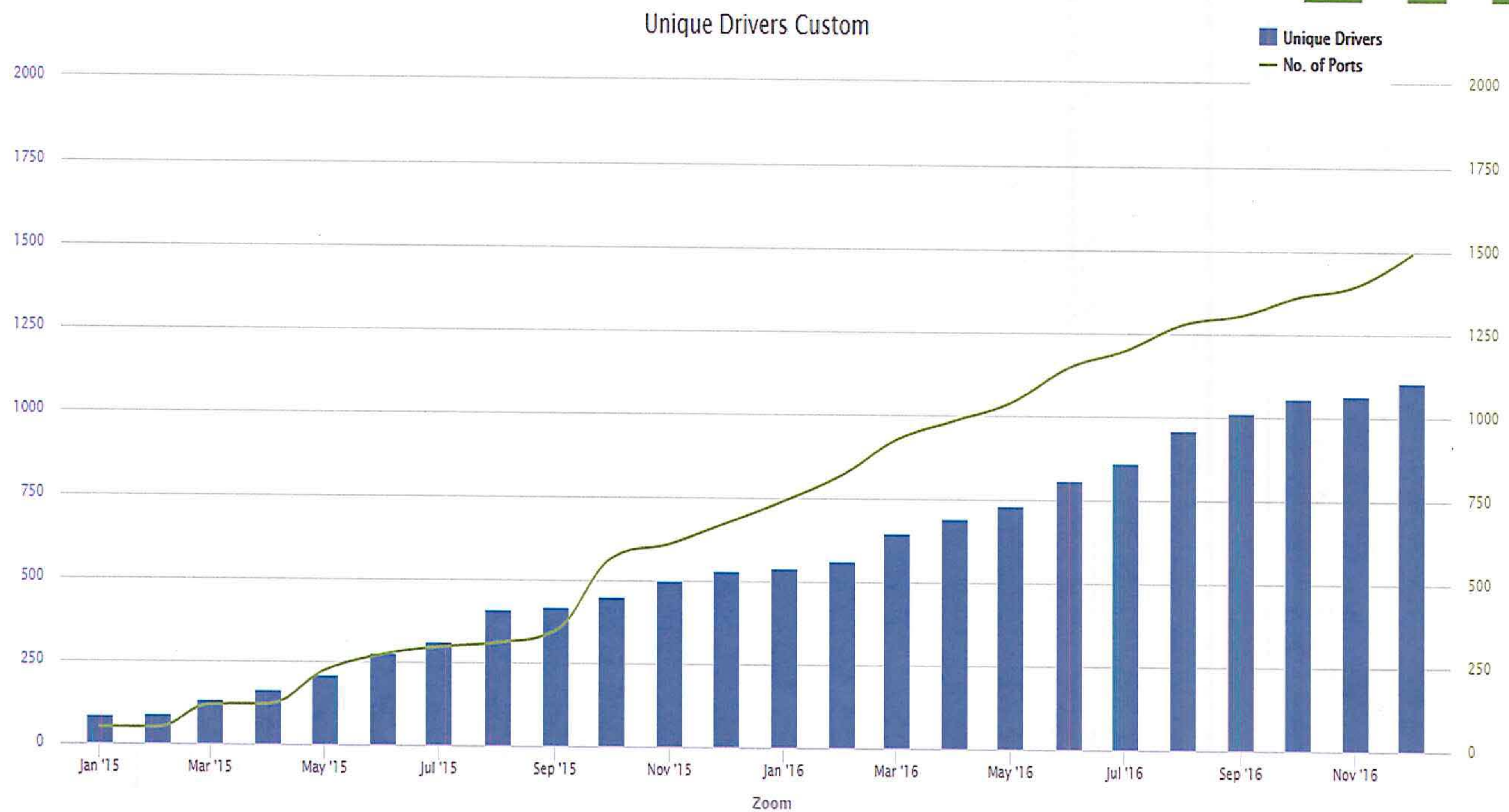
KCP&L®

cleancharge network

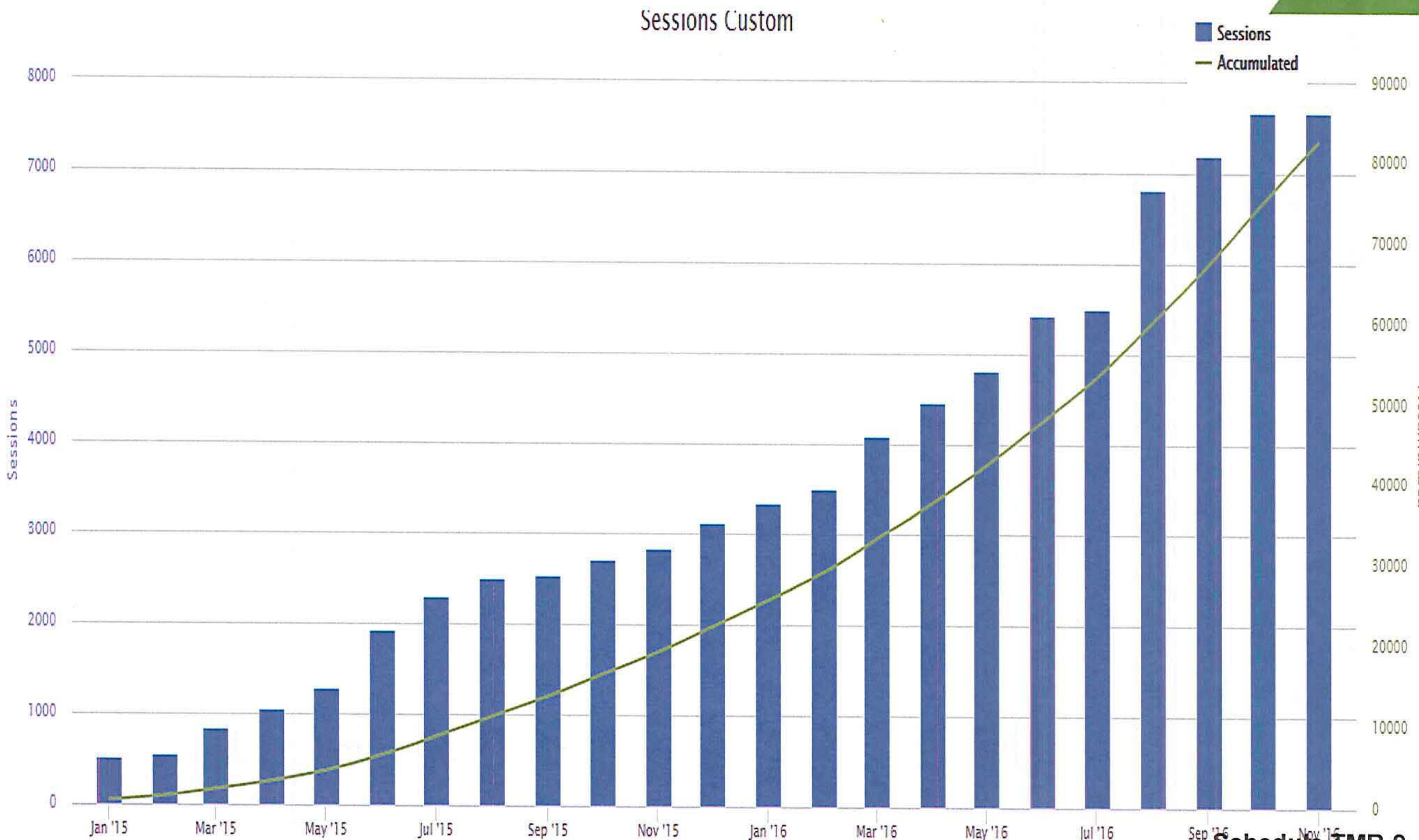
3Q 2016 Update: Top 5 Metros for EV Growth

Rank	Metro	Q3'15	Q4'15	Q1'16	Q2'16	Q3'16	Q3'16 quarterly YOY growth
1	Las Vegas	1,667	1,879	2,060	2,344	2,620	57%
2	Kansas City	1,027	1,122	1,212	1,338	1,587	55%
3	Raleigh/Durham	1,702	1,875	2,030	2,291	2,578	51%
4	Miami	5,169	5,700	6,218	6,978	7,657	48%
5	Denver	3,825	4,322	4,700	5,129	5,668	48%
6	Phoenix	5,064	5,501	5,937	6,534	7,209	42%
7	Philadelphia	4,028	4,366	4,716	5,126	5,730	42%
8	Portland	6,058	6,506	7,127	7,763	8,524	41%
9	LA	75,969	82,036	89,334	96,761	105,579	39%
10	San Diego	12,479	13,593	14,765	15,974	17,372	39%

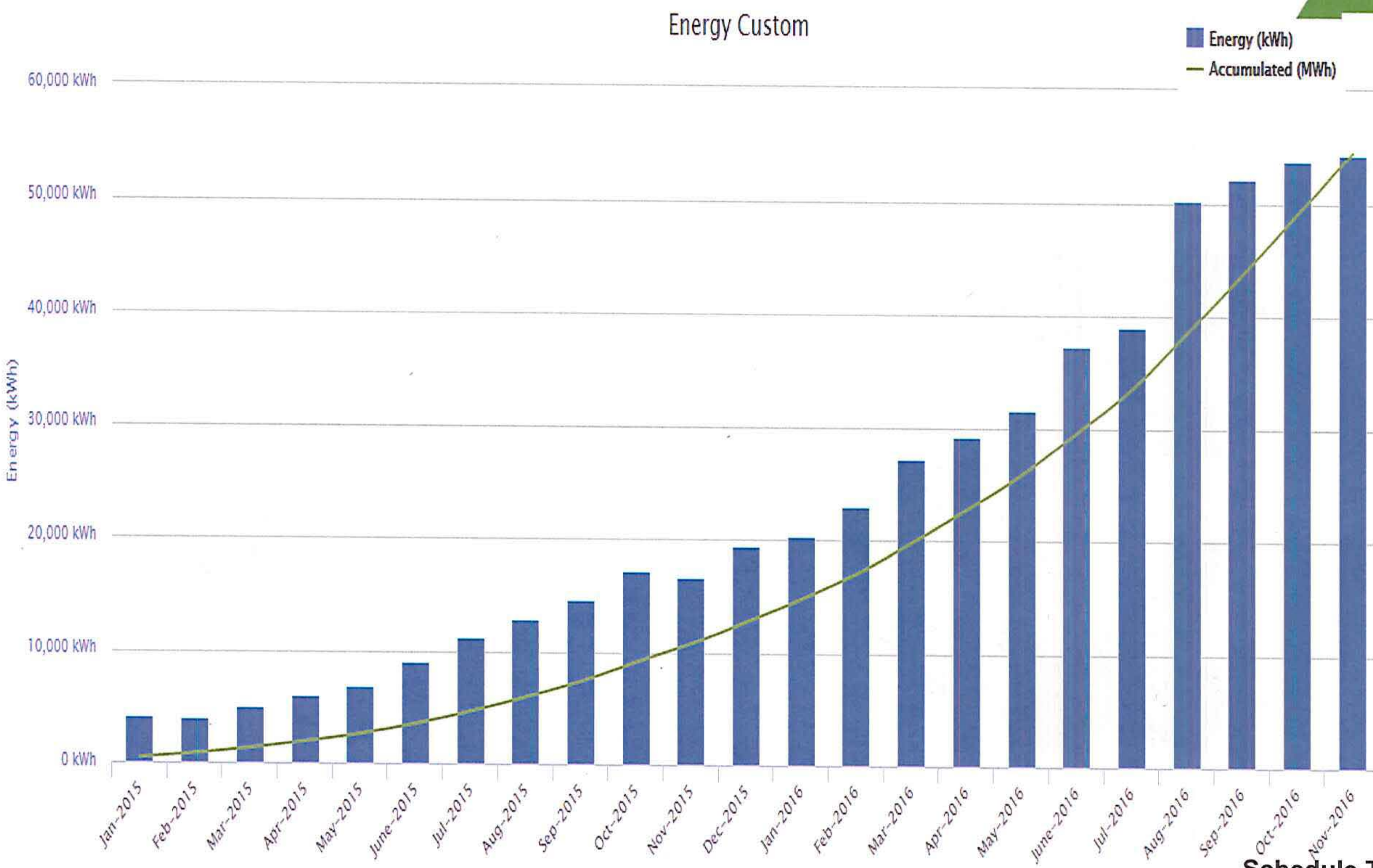
Unique Drivers – Updated



Monthly Sessions-Updated



Monthly Energy - Updated



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