Exhibit No.:	
Issue:	Class Cost of Study, Rate Design, Fuel Adjustment Clause
Witness:	Kavita Maini
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2014-0351
Date Testimony Prepared:	March 24, 2015

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	**)**	**File No. ER-2014-0351** Tariff No. YE-2015-0074

Surrebuttal Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

March 24, 2015

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)	Case No. ER-2014-0351

STATE OF WISCONSIN	)	
	)	SS
COUNTY OF WAUKESHA	)	

AFFIDAVIT OF KAVITA MAINI

Kavita Maini, being first duly sworn, on her oath states:

1. My name is Kavita Maini. I am a consultant with KM Energy Consulting, LLC. having its principal place of business at 961 North Lost Woods Road, Oconomowoc, WI 53066. I have been retained by the Midwest Energy Consumers' Group ("MECG") in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0351.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

Kavita Maini

Subscribed and sworn to before me this ___ day of February, 2015.

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

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**BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	**)**	**File No. ER-2014-0351** Tariff No. YE-2015-0074

Surrebuttal Testimony of Kavita Maini

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. PLEASE STATE YOUR BUSINESS ADDRESS.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. ARE YOU THE SAME KAVITA MAINI WHO HAS PREVIOUSLY FILED DIRECT AND REBUTTAL TESTIMONY IN THIS CASE?

A. Yes, I filed direct and rebuttal testimony on behalf of the Midwest Energy Consumers Group ("MECG").

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A The purpose of my rebuttal testimony is to address rebuttal testimony from parties regarding fuel adjustment clause; residential and industrial rate comparisons; interruptible credit recovery associated with Schedule SC-P; class cost of service study ("CCOSS") issues; and revenue neutral adjustments. I also reinforce certain rate design recommendations from my direct testimony.

II. FUEL ADJUSTMENT CLAUSE (FAC)

Q WHY DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY THAT TRANSMISSION COSTS SHOULD NOT BE INCLUDED IN THE FAC?

A My reasoning was two-fold:

First, I indicated that Empire has not provided an adequate assessment of benefits associated with SPP Integrated Marketplace ("IM"). The development of this marketplace was one of the primary arguments that the Company has made in support of including SPP related transmission costs in the FAC. I indicated that the Company needed to provide an updated analysis of ratepayer benefits associated with the IM prior to any inclusion of SPP transmission costs;

Second, I testified that Empire's proposal to recover fixed transmission costs, incurred on a per kW basis ($/KW) through a variable energy charge ($/kWh) contradicted the Company's rate design objective of reducing or eliminating recovery of fixed costs through energy charges.

Q HOW DID THE COMPANY RESPOND TO THE ISSUE OF ESTIMATING BENEFITS?

A In rebuttal testimony, Empire witness Tartar indicates that I did not provide any suggestions for a more reasonable estimate. Tarter fails to recognize, however, that the onus is on the Company to demonstrate the reasonableness of its proposal. Providing outdated study results or results that do not include at a minimum, one year impact of participating in the SPP IM, does not provide a demonstration of quantifiable benefits. In fact, witness Tartar indicated that he made the SPP IM related adjustment outside of the production cost model used to calculated base fuel costs in part because "it would take time for the SPP IM to mature and for analysts to gain confidence in the market based model approach." (See Tartar Rebuttal testimony at page 4). I can certainly understand that more time is needed to get comfortable with the many changes associated with the SPP IM. This is exactly my point in recommending that the Company not include SPP related transmission expenses in the FAC in this case.

Q DO YOU HAVE ADDITIONAL CONCERNS?

A Yes. I asked the Company to provide a five year projection of SPP related transmission expansion costs to which Empire will be subjected. The following Table shows the projected costs provided by Empire for Regional Base Plan funding costs:

	Regional Base Plan Funding
2015	$10,354,281
2016	$12,446,852
2017	$14,091,845
2018	$15,169,617
2019	$16,205,542

Source: See response to MECG 8-12

While these costs increases appear to be significant, I have two fundamental problems with including these costs in the FAC.

First, while these cost increases are significant, they do not demonstrate the volatility that the Commission has typically required for inclusion of costs in an FAC. As the Commission has previously recognized, cost increases do not equate to cost volatility. If costs are known and rising, and allowed recovery through the FAC between rate cases, it allows the utility to recover these costs while at the same time not having to consider whether there are any offsetting changes in non-fuel revenues or expenses. As explained in the Commission Order in Ameren UE's case ER-2007-0002, page 23:

> Markets in which prices are volatile tend to go up and down in an unpredictable manner. When a utility's fuel and purchased power costs are swinging in that way, the time consuming ratemaking process cannot possibly keep up with the swings. As a result, in those circumstances, a fuel adjustment clause may be needed to protect both the utility and its ratepayers from inappropriately low or high rates. Because AmerenUE's costs are simply rising, that sort of protection is not needed. As Brosch explains, rising, but known, fuel costs are the worst reason to implement a fuel adjustment clause because such a fuel adjustment clause allows the utility to recover a single known rising cost while avoiding a rate case in which all its other expenses and revenue, which are changing in the background, will be examined and perhaps used to offset all or part of the rising fuel cost to avoid an unnecessary rate increase."

The transmission costs seem to be reasonably projected and known to be increasing as indicated in response to MECG8-12. Given this, Empire can easily time its rate cases to capture the increases in these costs. In fact, Empire has already informed the parties that it will be filing another rate case immediately following the conclusion of this case.

Second, while the Company's preference is to recover these costs through the FAC based simply on the notion that these costs are increasing, I would argue that this is precisely the reason why customers should not be subjected to these costs until a reasonable opportunity has been afforded to thoroughly conduct discovery and examine the reasonableness of these costs. If the recovery of transmission related costs is implemented through the FAC, it essentially shifts the burden of proof away from the Company and to Commission staff to prove why certain costs should not be recovered after the fact - this is a difficult and unfair proposition particularly when one considers the myriad of fuel related issues that Commission staff typically examine during the prudency review.

Q DID EMPIRE RESPOND TO YOUR CONCERNS ABOUT RECOVERY OF FIXED COSTS THROUGH VOLUMETRIC CHARGES?

A No, Empire has not addressed my concerns. I had indicated the following serious concern on page 12 of my direct testimony:

> "The Company's witness Edwin Overcast has indicated concerns that Empire's rates rely too heavily on the volumetric recovery of fixed costs. He indicates that volumetric recovery of fixed costs does not assign costs to cost causers and sends misleading pricing signals. I agree and share his concerns. Despite this stated concern, the Company's proposal to include fixed costs such as fixed natural gas transportation costs and transmission costs in the FAC and recover them through a volumetric charge: a) will further exacerbate the issue of assigning costs to cost causers, b) will send flawed pricing signals and c) will result in economic inefficiency. Given this inconsistency and unintended consequences, it dictates that these fixed costs be recovered through base rates."

Should the Commission allow the Company to include recovery of transmission costs through the FAC, I recommend that Empire establish a $/KW demand charge for recovery of fixed costs for demand metered customer classes to address the above mentioned concerns.

Q HAVE YOU SEEN OTHER JURISDICTIONS PASS TRANSMISSION COSTS SUCH AS NETWORK INTEGRATED SERVICE OR TRANSMISSION EXPANSION COSTS THROUGH THE FAC?

A While not included in the fuel adjustment clause, some jurisdictions allow for recovery of these transmission costs between rate cases. In those instances, the cost recovery for demand metered customers is a $/KW charge in all of these jurisdictions.[1] Further, the rider proceedings, for example, in Minnesota, afford the opportunity for discovery and comments by interested parties prior to approving cost recovery.

III. RATE COMPARISONS

Q IN DIRECT TESTIMONY, YOU HIGHLIGHTED CONCERNS ABOUT EMPIRE'S AVERAGE INDUSTRIAL RATES. HOW DID THE COMPANY'S RESPOND TO THESE CONCERNS?

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[1] See for example, https://www.alliantenergy.com/wcm/groups/wcm_internet/@int/@tariff/documents/document/mdaw/mdi2/~edisp/026387.pdf; http://www.xcelenergy.com/Company/Rates_&_Regulations/Minnesota_Rates,_Rights_and_Service_Rules

A Empire witness Walters indicates that I did not identify the reasons why Empire rates are higher than other regional and national electric utilities. She also testifies that other utilities are lagging with respect to environmental compliance and that their rates will catch up once they incur these environmental compliance related costs.

Q DO YOU AGREE WITH EMPIRE'S EXPLANATION?

A No. I find it hard to believe that Empire is significantly farther ahead of other utilities with respect to environmental compliance that this causes its rates to exceed the average on a national level. Utilities across the country are all facing the same regulations and implementing retrofits to comply with them. Second, the primary reason that I raised concerns about the affordability of Empire's rates was to show the difference between the affordability of residential and industrial rates relative to their respective national averages. Specifically, while Empire's residential rate is below the national average rate, Empire's industrial rate is above the national average. Assuming arguendo that Empire is far ahead in terms of environmental compliance relative to other utilities in the country, it does not explain why residential rates are below the national average and industrial rates are above the national average. As explained in my direct testimony, and as reflected in all the class cost of service studies in this case, a critical factor is that costs have not been assigned to those classes that cause the costs thereby leading to a misalignment of rates with the embedded costs to serve. Indeed, the residential class rates have deviated further from cost to serve compared to the previous rate case (see OPC Witness Dismukes direct testimony).

IV. COST ALLOCATION OF INTERRUPTIBLE CREDITS: SCHEDULE SC-P

Q WHAT IS THE DISPUTE REGARDING COST RECOVERY ASSOCIATED WITH SCHEDULE SC-P'S INTERRUPTIBLE CREDITS?

A Commission Staff recommends that Empire not be allowed to recover the credits that Empire pays for interrupting Praxair's load. Staff's recommended approach is apparently based upon the faulty notion that other ratepayers do not receive a benefit associated with these interruptible credits. On the other hand, Empire indicates that the Company has recovered the cost of these credits in Empire's revenue requirement in past cases. (See Keith Rebuttal testimony at page 11).

Q HAS COMMISSION STAFF PREVIOUSLY ACKNOWLEDGED THE VALUE OF INTERRUPTIBLE LOAD AND RECOMMENDED RECOVERY OF THE INTERRUPTIBLE CREDIT COSTS?

A Yes. In the 2010 KCPL case, Staff stated the following:

> "**PLCC/MPower:** Peak load curtailment credits are paid to customers that agree to curtail a portion of their peak load when requested by KCPL. ***<u>These discounts are assumed to be a benefit to all ratepayers and thus are not excluded from the determination of KCPL.s revenues</u>***."
> See Commission Staff Revenue Requirement Cost of Service Report in ER-2010-0355 (emphasis added).

Further, it is my understanding that the Staff has allowed for recovery of the interruptible credits associated with the two customers that are provided service under the IR rate schedule.

Thus, Staff is being inconsistent in the treatment of interruptible credit costs in the current Empire case and does not provide any reasonable justification for such inconsistent treatment. Further, Empire indicates that the Commission has allowed for the recovery of these credits in the Company's revenue requirements in prior years.

It appears that Staff is confused about the underlying rationale of the Schedule SC-P tariff. As I have discussed in my rebuttal testimony, while the tariff is labeled as Special Contract, there is no special discount for load retention provide in this Schedule. Rather, this is simply another example of an interruptible rate schedule and the credits should be treated in a manner similar to the IR credits in this case and the Mpower credits in the KCPL case. The need for the SC-P rate schedule, in addition to the IR rate schedule, is because of the unique terms of the schedule. Specifically, Empire is allowed to interrupt Praxair's load on much shorter notice. As a result, it is a different form of interruptible rate than the Interruptible Rider. I am attaching the SC-P tariff as **SCHEDULE KM-1ST** as reference.

Q WHAT IS YOUR POSITION ON THIS ISSUE?

A My position is that it is reasonable for the Company to include the costs of the SC-P interruptible credit in its revenue requirement. As described in my direct (and rebuttal) testimony, having interruptible load benefits all customers. Therefore, recovering these costs from all firm load customers is reasonable. Such an approach is conventional and typically applied in other jurisdictions. The credit is not a load retention discount, but compensation for providing interruptible service. Thus, I recommend that Empire be allowed to include in its revenue requirements, the cost of the interruptible credits provided to Schedule SC-P.

V. CLASS COST OF STUDY (CCOSS)

1. OPC Witness David Dismukes

Q WHAT DID OPC WITNESS DAVID DISMUKES INDICATE REGARDING MY CCOSS METHODOLOGY FOR FIXED PRODUCTION PLANT?

A Witness Dismukes did not indicate any concerns regarding my CCOSS methodology and found that our methodologies were similar. However, as I indicated in my rebuttal, I had concerns with his CCOSS approach utilizing the 12CP allocator as well as allocating certain distribution costs 100% on the basis of demand allocators. (See pages 7 – 10 of my rebuttal). I also had issues with OPC not firming up revenues associated with interruptible class Schedule SC-P. (See pages 3-4 of my rebuttal testimony).

2. Empire Witness Overcast

Q WHAT DID THE COMPANY'S WITNESS OVERCAST INDICATE REGARDING YOUR CCOSS METHODOLOGY FOR FIXED PRODUCTION PLANT?

A Witness Overcast does not agree with my use of six non-coincident peaks in the AED method. He testifies that "using only six peaks based solely on load does not adequately represent either how the system is planned or how the system is operated to minimize the total cost of power supply services including reserves." (See Overcast

Rebuttal Testimony at page 3). As already explained in my rebuttal, Mr. Overcast has not provided any evidence to substantiate his claim that by incorporating planned or forced outages, the 12 CP approach becomes more valid. Further, when asked to provide actual reserve margins by month to ascertain the impact of outages on reserve margins, Empire indicated that it does not have such information (see response to MECG 8.3). If the Company does not have such information, it is difficult to understand how it incorporates such information in its capacity planning. In addition, since the advent of SPP IM, the Company carries lower operating reserves and SPP coordinates outages. As a result, outages in an isolated system pre-SPP IM compared to now being part of SPP IM, a regional co-optimized energy and ancillary (i.e., operating reserves) market, are far less concerning, especially in non-peak periods. There is system diversity which allows greater flexibility to market participants.

3. Commission Staff

Q DID STAFF PROVIDE ANY FEEDBACK REGARDING YOUR CCOSS METHODOLOGY?

A No. I would note, however, that I had previously criticized Staff's methodology because of its failure to firm up revenues for the SC-P class in its CCOSS. Since that time, I have had an informal discussion with Staff witness Sarah Kleithermes. She indicated that Staff indeed firmed up revenues for Schedule SC-P. I have reviewed her workpapers and confirm this point.

Q DID STAFF PROVIDE UPDATED CCOSS RESULTS IN REBUTTAL TESTIMONY?

A Yes, Staff presented updated CCOSS results of its detailed BIP methodology and adjusted the revenue deficiency from 1.39% to 2.64%. In my rebuttal testimony, I discussed major reasons why I do not agree with Staff's detailed BIP CCOSS approach for allocating fixed production plant. I continue to maintain this position for the same reasons identified in my rebuttal testimony. As also discussed in my rebuttal testimony, Staff's Average and Excess option using 4NCP is a more reasonable approach. The AED method has also been approved by the Commission in past cases and other utilities (e.g., Ameren use of AED4NCP) utilize this approach for allocation of fixed production plant. Staff provided results of its AED4NCP allocator in direct testimony, but did not update these results in its rebuttal testimony like it did for the BIP methodology. That said, however, I was able to use the AED4NCP allocator from Staff's rebuttal testimony to calculate the updated CCOSS results.[2] The revenue deficiency and revenue neutral results are presented in the table below. Detailed results are provided in **SCHEDULE KM-2ST.** These results using Staff's updated data from rebuttal testimony are consistent with my CCOSS results in direct testimony in that all classes except for the residential class need a negative revenue neutral adjustment to align with costs to serve. I followed the Staff method of deducting the revenue deficiency amount of 2.64% from each class to calculate the 100% revenue neutral adjustment required.

[2] Similar to Empire, Staff also classified PPA demand as energy related. I changed this to demand related.

Table 1: CCOSS Results Using Staff's AED4NCP Allocator

	MECG USING STAFF AED4NCP		Revenue Neutral Change Needed	
Customer Class	Revenue Deficiency	CCOSS % Increase	MECG Using Staff AED4NCP	%
Residential	$25,967,485	12.6%	$20,711,692	10.1%
Commercial Bldg	($1,203,279)	-2.8%	($2,299,971)	-5.3%
Commerical Space Htg	$228,513	2.2%	($40,593)	-0.4%
Total Elec Bldg	($1,078,638)	-2.8%	($2,051,338)	-5.4%
General Power	($6,849,117)	-8.0%	($9,024,531)	-10.6%
Large Power	($4,413,171)	-7.4%	($5,939,326)	-9.9%
Schedule SC-P	($27,532)	-0.7%	($124,356)	-3.3%
Feed Mill	($23,244)	-20.1%	($26,194)	-22.6%
Lighting	($1,006,257)	-12.9%	($1,205,432)	-15.4%
	$11,594,760	2.6%		

For comparison purposes, I am also including Staff's detailed BIP results provided in Staff's rebuttal testimony in Table 2 below.[3]

Table 2: Staff's Detailed BIP CCOSS Results

	STAFF Detailed BIP Results		Revenue Neutral Change Needed	
Customer Class	Revenue Deficiency	CCOSS % Increase	Staff Detailed BIP	%
Residential	$22,014,612	10.7%	$16,777,956	8.1%
Commercial Bldg	$118,105	0.3%	($978,587)	-2.4%
Commerical Space Htg	$13,104	0.1%	($256,002)	-2.5%
Total Elec Bldg	($1,548,885)	-4.1%	($2,521,585)	-6.7%
General Power	($4,484,350)	-5.3%	($6,659,764)	-7.9%
Large Power	($3,381,708)	-5.7%	($4,907,863)	-8.3%
Schedule SC-P	$199,813	5.3%	$102,989	2.6%
Feed Mill	($40,577)	-35.1%	($43,527)	-37.7%
Lighting	($1,295,350)	-16.6%	($1,494,525)	-19.2%
	$11,594,764	2.6%		

Source: Robin Kleithermes Rebuttal Testimony, Page 5

[3] I would note that I ran Staff's CCOSS model using AED6NCP as well and the results are similar. The revenue neutral adjustment is more positive for the residential class and more negative for GP and LP classes compared to Staff's AED4NCP CCOSS results shown in Table 1.

Both CCOSS results indicate that significant positive revenue neutral adjustments are required for the residential class while significant negative revenue neutral adjustments are required for the GP, LP, TEB, Lighting and Feed Mill classes. The results vary in particular with respect to the Schedule SC-P class. This is because Schedule SC-P is a very high load factor class. As highlighted in my rebuttal testimony, Staff's detailed BIP methodology is problematic and results in allocating a disproportionate amount of fixed production costs to high load factor classes than is appropriate.

VI. REVENUE NEUTRAL ADJUSTMENTS

Q DO YOU CONTINUE TO BELIEVE THAT THERE SHOULD BE REVENUE NEUTRAL ADJUSTMENTS?

A Yes, it is important to move classes closer to CCOSS results. Staff has recommended slight movements namely, 0.85% negative adjustments for TEB, GP and LP and positive adjustment of 0.75% for the residential class. Staff made these recommendations in spite of the fact that its detailed BIP CCOSS indicated for example, that that the residential class needs 8.1% revenue neutral adjustment in direct testimony (see Table 2, page 8, Staff CCOSS Report). While making revenue neutral adjustments is a step in the right direction, Staff's proposed adjustments are too small to have a meaningful impact in bringing classes closer to costs to serve. Specifically, given the 8.1% revenue neutral shift needed to bring residential rates to cost of service, it would take almost 11 rate cases for residential rates to reach cost of service. Given that it has had 6 rate increase in 8 ½ years, Empire has averaged a rate increase every 17 months. Therefore, it would take over 15 ½ years to bring residential rates in line with cost of service under Staff's "gradual" approach.

While it is equitable for each class to pay what it costs to serve, I agree that making 100% revenue neutral adjustments in one rate case may be too punitive and some amount of gradualism is necessary. In Table 3 below, I provide the results of a 25% and 50% revenue neutral change using Staff's AED4NCP allocator for fixed production plant. I recommend that in this rate case, the Commission consider revenue neutral adjustments between 25% and 50% of the total revenue neutral adjustments needed to bring each of the classes closer to costs to serve. For example, for the residential class, this would mean a positive revenue neutral adjustment of 2.5% to 5%. Any revenue increase authorized to Empire can then be implemented in an across-the board increase after making these revenue neutral adjustments.

Table 3: Revenue Neutral Adjustments Using Staff's AED4NCP Allocator

	Revenue Neutral Change Needed		25% Revenue Neutral Change		50% Revenue Neutral Change	
Customer Class	MECG Using Staff AED4NCP	%	Amount	%	Amount	%
Residential	$20,711,692	10.1%	$5,177,923	2.5%	$10,355,846	5.0%
Commercial Bldg	($2,299,971)	-5.3%	($574,993)	-1.3%	($1,149,985)	-2.7%
Commerical Space Htg	($40,593)	-0.4%	($10,148)	-0.1%	($20,296)	-0.2%
Total Elec Bldg	($2,051,338)	-5.4%	($512,835)	-1.3%	($1,025,669)	-2.7%
General Power	($9,024,531)	-10.6%	($2,256,133)	-2.6%	($4,512,265)	-5.3%
Large Power	($5,939,326)	-9.9%	($1,484,831)	-2.5%	($2,969,663)	-5.0%
Schedule SC-P	($124,356)	-3.3%	($31,089)	-0.8%	($62,178)	-1.6%
Feed Mill	($26,194)	-22.6%	($6,549)	-5.7%	($13,097)	-11.3%
Lighting	($1,205,432)	-15.4%	($301,358)	-3.9%	($602,716)	-7.7%

As I discussed in my rebuttal testimony, all parties' CCOSS results indicate that the residential class needs a large positive revenue neutral adjustment. In Staff's rebuttal, Robin Kliethermes CCOSS results indicate a positive revenue neutral adjustment of over 8%. These results are from Staff's detailed BIP CCOSS methodology that tends to favor low load factor customer classes due to higher energy weightings. OPC also compared the CCOSS results from the previous case and concluded that the residential class results have deviated further from costs to serve. Thus, it is necessary to make more significant adjustments to prevent further deviations from costs to serve and to correct past deviations.

VII. RATE DESIGN

Q WHAT ARE YOUR FINAL RECOMMENDATIONS REGARDING RATE DESIGN CHANGES TO THE LP IN DIRECT TESTIMONY?

As discussed in my direct testimony, I support the Company's objectives to begin removing fixed costs from energy charges and, in fact, I made a number of recommendations to complement this objective and improve the pricing signals in the LP rate. My final recommendations regarding the LP rate are as follows:

1. As discussed in my direct testimony, all fixed costs should be removed from the second block energy rate. In my direct testimony, I had explained that this can be accomplished by adjusting this energy rate to coincide with the base cost of fuel. The suggestion that energy rates be reduced is also consistent with the fact that fuel costs have decreased since the last case. Upon further review, I recognize that variable production cost recovery should also be included in the second block energy

rate. At present the second block energy charge in the LP rate schedule is $0.035/kWh in the winter and $0.0363/kWh in the summer. I recommend that the second block be reduced by $0.005/kWh for both blocks respectively. With the base cost of fuel at $0.02747/kWh (as indicated in Tartar's direct testimony), there is room for recovery of variable production costs by not reducing the second block all the way to the base cost of fuel. The fixed costs removed from the second energy block should instead be recovered through the Billing Demand charge. This increase in the billing demand charge is consistent with the utility's primary case driver (the capital costs of the AQCS at the Ashbury Generation Power Plant) and sends an appropriate pricing signal. Further, the revised second block charge will be a more realistic representation of average energy costs. Witness Overcast indicated in his direct testimony that 69% of the current rate revenue is recovered volumetrically in the LP class and that "even after excluding the cost of energy, the portion of volumetric recovery is still significant and is an unacceptable basis for meeting the standard of just and reasonable rates." (See Overcast Direct at pages 23-24). My recommendations will result in appropriately rebalancing the rate design of the LP rate to achieve the Company's desired objectives.

2. I continue to recommend that similar to the Schedules SC-P and SC-T, Empire should also time differentiate the billing demand charge in the Large Power rate schedule to send the proper capacity price signals regarding transmission and generation infrastructure costs. Time differentiation of the billing demand sends pricing signals that encourage industrial customers to shift operations to move any peaks to an off-peak period. In this way, future utility capacity additions can either be

postponed or cancelled. MECG requests that the Commission order Empire to submit a Large Power rate schedule in its next case that recognizes a time differentiated billing demand charge.

Q DID ANY WITNESS IDENTIFY CONCERNS REGARDING THESE RECOMMENDATIONS IN PREVIOUS ROUNDS OF TESTIMONY?

A No.

Q WHAT WERE YOUR RECOMMENDATIONS REGARDING RATE DESIGN CHANGES TO SCHEDULE SC-P IN DIRECT TESTIMONY?

A For the same reasons discussed above for the LP rate, I support the Company's recommendation to move recovery of fixed costs out of energy charges and into demand charges. For a variety of reasons described in my direct testimony, however, I recommend that the offset associated with reducing the SC-P energy charges be applied to the <u>billing</u> demand charges instead of the <u>facility</u> demand charge. I continue to recommend these changes.

Q DID ANY WITNESS IDENTIFY CONCERNS REGARDING THESE RECOMMENDATIONS?

A No.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes.

SPECIAL TRANSMISSION SERVICE CONTRACT: PRAXAIR
SCHEDULE SC-P

AVAILABILITY:

This schedule is available for electric service to PRAXAIR, INC. (Customer) as stated in the contract for power service between THE EMPIRE DISTRICT ELECTRIC COMPANY (Company) and PRAXAIR, INC. ("the contract").

MONTHLY RATE:

	Summer Season	Winter Season
CUSTOMER ACCESS CHARGE	$ 246.47	$ 246.47
ON-PEAK DEMAND CHARGE		
Per kW of Billing Demand	23.95	16.27
SUBSTATION FACILITIES CHARGE		
Per kW of Facilities Demand..	0.481	0.481
ENERGY CHARGE, per kWh:		
On-Peak Period	0.0515	0.0365
Shoulder Period	0.0416	
Off-Peak Period	0.0321	0.0303

The Summer Season will be the first four monthly billing periods billed on and after June 16, and the Winter Season will be the remaining eight monthly billing periods of the calendar year. The On-Peak hours will be weekdays, excluding holidays, from 12:00 p.m. through 7:00 p.m. during the Summer Season and 6:00 a.m. through 10:00 p.m. during the Winter Season. The Shoulder hours will be weekends from 12:00 p.m. through 9:00 p.m. and weekdays from 9:00 a.m. through 12:00 p.m. and 7:00 p.m. through 10:00 p.m. during the Summer Season. All other hours are Off-Peak. Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, as specified by the North American Electric Reliability Council (NERC).

FUEL ADJUSTMENT CLAUSE:

The above charges will be adjusted in an amount provided by the terms and provisions of the Fuel Adjustment Clause, Rider FAC.

ENERGY EFFICIENCY COST RECOVERY:

The above charges will be adjusted to include a charge of $0.00027 per kWh on all customers who have not declined to participate in Company's energy efficiency programs under P.S.C. Rule 4 CSR 240-20.094(6).

DETERMINATION OF DEMANDS (CPD, MFD, ID):

An appropriate level of demand at the time of the Company's system peak shall be determined for PRAXAIR under this Schedule. This Customer Peak Demand ("CPD") shall be either PRAXAIR's actual maximum measured kW demand during a peak period, or a calculated amount based upon conditions involving PRAXAIR's actual or expected operations, and agreed upon between Company and PRAXAIR.

CURTAILMENT LIMITS:

The number of Curtailment Events in a Curtailment Year shall be no more than thirteen (13). Each Curtailment Event shall be no less than two or no more than eight consecutive hours and no more than one occurrence will be required per day unless needed to address a system reliability event. The cumulative hours of curtailment per Customer shall not exceed one hundred hours (100) during each Curtailment Year. The Curtailment Contract Year shall be June 1 through May 31.

DETERMINATION OF BILLING DEMAND:

The monthly "On-Peak Demand" shall be determined as being the highest fifteen (15) minute integrated kilowatt demand registered by a suitable demand meter during the peak hours as stated above. In no event shall the Peak Demand be less than the lesser of 6000 kW or Customer's MFD for Customers that have contracted interruptible capacity as specified in the contract or any future amendments thereto.

DETERMNATION OF MONTHLY FACILITIES DEMAND:

The monthly "Substation Facilities Demand" shall be determined as being the highest fifteen (15) minute integrated demand registered by a suitable demand meter during all hours. In no event shall Substation Facilitiy Demand, if applicable be less than the greater of 6000 kW and Customer's CPD for Customers that have contracted interruptible capacity as specified in the contract or any future amendments thereto.

METERING ADJUSTMENT:

The above rates apply for service metered at transmission voltage. Where service is metered at substation voltage, metered kilowatts and kilowatt-hours will be increased prior to billing by multiplying metered kilowatts and kilowatt-hours by 1.0086.

SPECIAL TRANSMISSION SERVICE CONTRACT: PRAXAIR
SCHEDULE SC-P

SUBSTATION FACILITIES CHARGE:

The above Substation Facilities Charge does not apply if the stepdown substation and transformer are owned by the Customer.

PAYMENT:

The above rate applies only if the bill is paid on or before fifteen (15) days after the date thereof. If not so paid, the above rate plus 5% then applies.

MONTHLY CREDIT:

A monthly credit of $4.01 on demand reduction per kW of contracted interruptible demand for substation metered Customers will be applied.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, gross or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a flat sum payment, a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. When such tax or fee is imposed on the Company as a flat sum or sums, the proportionate amount applicable to each Customer's bill shall be determined by relating the annual total of such sum(s) to the Company's total annual revenue from the service provided by this tariff within the jurisdiction of the governmental body and the number of customers located within that jurisdiction. The amounts shall be converted to a fixed amount per customer, so that the amount, when accumulated from all customers within the geographic jurisdiction of the governmental body, will equal the amount of the flat sum(s). The fixed amount per customer shall be divided by 12 and applied to each monthly bill as a separate line item. The amount shall remain the same until the flat sum may be changed by the governmental body, in which case this process shall be adjusted to the new flat sum. The amount shall be modified prospectively by the Company anytime it appears, on an annual basis, that the Company is either over-collecting or under-collecting the amount of the flat sum(s) by more than five percent (5%) on an annual basis. Bills will be increased in the proportionate amount only in service areas where such tax or fee is applicable.

SPECIAL CONDITIONS OF SERVICE:

1. The minimum ID shall be at least 5600 kW.
2. The Company will give Customer a minimum of 30 minutes notice prior to demand reduction.
3. The Company may request a demand reduction on any day.
4. This schedule, SC-P, is available for service to Praxair, Inc. only in the event there is a contract for power service in effect between the Company and Praxair, Inc.

The Empire District Electric Company
Case No. ER-2014-0351
Test Year 12 Months Ending April 30, 2014
Updated through August 31, 2014
CCOS Summary

Line Number	Functional Category	Class Cost of Service	Allocator Number	Residential	CB	SH	TEB	GP	LP	SC-Praxair	PFM	Lighting
1	Production Capacity	$128,614,249	6-A&E Capacity	$64,261,336	$10,648,927	$3,028,617	$11,308,211	$22,468,820	$14,360,323	$1,113,810	$28,072	$1,396,133
2	Production Energy	$0	7-Sales @ Generation	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Transmission	$42,263,881	8-12 CP (Summary)	$21,803,798	$3,090,460	$1,018,914	$4,014,874	$7,109,136	$4,822,544	$346,301	$3,427	$54,426
4	Dist - Substation	$13,155,068	9-NCP @ Substation	$6,810,581	$1,154,370	$321,616	$1,141,021	$2,276,411	$1,297,691	$0	$3,413	$149,965
5	Dist - Primary	$30,527,181	10-NCP @ Primary	$15,804,378	$2,678,777	$746,344	$2,647,833	$5,282,566	$3,011,375	$0	$7,895	$348,013
6	Dist - Secondary	$7,272,315	11-Peak NCP @ Secondary	$4,199,883	$711,865	$198,330	$703,634	$1,237,548	$126,474	$0	$2,103	$92,477
7	Production Energy -Sales	$137,131,094	7-Sales @ Generation	$56,238,491	$10,542,689	$3,053,100	$12,364,108	$28,027,299	$23,796,911	$2,001,314	$21,600	$1,085,583
8	BIP Fuel in Storage	$0	7-Sales @ Generation	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	BIP O&M	$0	6-A&E Capacity	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Dist - Min Demand	$26,565,798	12-# of Customers Less Transmission	$22,344,129	$3,129,540	$544,823	$164,759	$294,048	$6,739	$0	$1,596	$80,163
11	Dist - Transformers	$549,319	24-Transformer Expense	$386,505	$57,722	$12,195	$22,753	$44,291	$22,121	$30	$80	$3,622
12	Dist - Services	$9,557,321	14-Dist-Services - Company Study	$7,584,810	$1,384,463	$241,022	$92,704	$218,153	$0	$0	$706	$35,463
13	Dist - Meters	$8,962,700	15-Meters - Company study	$5,646,418	$1,972,533	$343,399	$280,980	$501,469	$152,337	$14,031	$1,006	$50,526
14	Cust. Deposit	-$639,598	16-Deposit - Company study	-$303,656	-$121,540	-$38,595	-$78,250	-$94,054	-$1,273	$0	-$19	-$2,212
15	Cust. Meter Read	$3,487,568	17-Meter Reading - Company study	$2,918,591	$404,407	$70,323	$26,574	$49,256	$5,275	$231	$1,990	$10,921
16	Cust. Billing Other	$8,350,755	18-Cust. Billing Other	$7,031,077	$867,365	$151,250	$71,137	$145,600	$57,958	$2,652	$389	$23,327
17	Uncollectible Accts.	$2,282,437	19-Uncollectible Accts. (Account 904)	$1,836,203	$194,248	$28,303	$53,281	$132,882	$0	$0	$0	$37,520
18	Cust. Services & Info Ex.	$2,559,816	20-Cust. Services & Info. Expense	$1,538,941	$462,826	$80,481	$25,344	$46,976	$383,106	$10,082	$190	$11,872
19	Sales Expense	$509,301	21-Sales Expenses (Accounts 911 thru 916)	$408,729	$23,358	$4,062	$8,355	$15,695	$51	$1	$33	$49,015
20	Energy Efficiency	$1,331,565	23-Energy Efficiency	$613,991	$113,187	$32,743	$128,699	$278,921	$163,792	$0	$232	$0
21	Income Taxes	$33,154,837	25-Income Tax Allocator	$8,644,710	$3,918,121	$779,821	$3,463,480	$9,069,390	$5,841,184	$239,157	$18,048	$1,180,925
22	Revenue Related	$0	22-Revenue Related	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Lighting Function	$2,114,120	26-Lighting	$0	$0	$0	$0	$0	$0	$0	$0	$2,114,120
24	Excess Facilities	$1,092,367	36-Total Excess Facilities	$0	$1,715	$0	$21,026	$243,735	$825,188	$703	$0	$0
	CLASS COST OF SERVICE	$458,842,093		$227,768,915	$41,235,033	$10,616,748	$36,460,523	$77,348,142	$54,871,796	$3,728,312	$90,761	$6,721,859
25	CURRENT RATE REVENUE	$453,947,905		$205,359,046	$43,007,523	$10,553,157	$38,145,113	$85,310,352	$59,849,215	$3,797,014	$115,705	$7,810,781
26	CURRENT OTHER REVENUE	-$6,700,572		-$3,601,889	-$571,574	-$161,427	-$582,785	-$1,086,380	-$572,613	-$41,195	-$1,635	-$81,074
27	TOTAL CURRENT REVENUE	$447,247,333		$201,757,157	$42,435,949	$10,391,730	$37,562,328	$84,223,972	$59,276,602	$3,755,819	$114,070	$7,729,707
28	REVENUE ABOVE (BELOW) COS	-$11,594,754		-$25,967,485	$1,203,279	-$228,513	$1,078,638	$6,849,117	$4,413,171	$27,532	$23,244	$1,006,257
29	% CHANGE NEEDED TO BRING CLASS REVENUE TO COST-OF-SERVICE	2.55420%		12.64492%	-2.79783%	2.16535%	-2.82772%	-8.02847%	-7.37382%	-0.72510%	-20.08902%	-12.88292%
30	Production Capacity	$138,631,426		$66,796,522	$11,767,020	$3,268,710	$12,495,159	$25,453,328	$16,071,117	$1,190,154	$35,040	$1,693,687
31	Prod. Energy											
32	BIP O&M	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
33	Production Energy -Sales	$147,811,609		$58,457,166	$11,649,628	$3,295,134	$13,661,886	$31,750,134	$26,631,918	$2,138,490	$26,961	$1,316,951
34	BIP Fuel in Storage	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Production Energy	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Energy Efficiency	$1,435,275		$638,214	$125,071	$35,339	$142,208	$315,970	$183,305	$0	$290	$0
37	Total Prod. Energy	$149,246,883		$59,095,380	$11,774,699	$3,330,473	$13,804,094	$32,066,103	$26,815,223	$2,138,490	$27,251	$1,316,951
38	Transmission	$45,555,622		$22,663,984	$3,414,945	$1,099,688	$4,436,289	$8,053,435	$5,397,070	$370,037	$4,278	$66,026
39	Dist - Substation	$14,179,656		$7,079,267	$1,275,574	$347,112	$1,260,786	$2,578,784	$1,452,289	$0	$4,260	$181,927
40	Dist - Primary	$32,904,803		$16,427,879	$2,960,037	$805,510	$2,925,758	$5,984,243	$3,370,130	$0	$9,855	$422,184
41	Distribution Secondary											
42	Excess Facilities	$1,177,446		$0	$1,895	$0	$23,233	$276,110	$923,495	$751	$0	$0
43	Dist - Secondary	$7,838,722		$4,365,573	$786,608	$214,053	$777,490	$1,401,930	$141,541	$0	$2,625	$112,186
44	Lighting Function	$2,278,779		$0	$0	$0	$0	$0	$0	$0	$0	$2,564,697
45	Dist - Min Demand	$28,634,886		$23,225,631	$3,458,129	$588,014	$182,053	$333,106	$7,542	$0	$1,992	$97,248
46	Dist - Transformers	$592,103		$401,753	$63,783	$13,162	$25,141	$50,174	$24,756	$32	$100	$4,394
47	Total Distribution Secondary	$40,521,937		$27,992,958	$4,310,414	$815,228	$1,007,917	$2,061,320	$1,097,335	$783	$4,717	$2,778,525
48	Customer											
49	Uncollectible Accts.	$2,460,206		$1,908,643	$214,643	$30,547	$58,874	$150,533	$0	$0	$0	$45,517
50	Dist - Services	$10,301,697		$7,884,040	$1,529,826	$260,129	$102,435	$247,130	$0	$0	$881	$43,021
51	Dist - Meters	$9,660,764		$5,869,176	$2,179,641	$370,622	$310,473	$568,079	$170,485	$14,993	$1,256	$61,294
52	Cust. Deposit	-$689,413		-$315,636	-$134,301	-$41,655	-$86,463	-$106,547	-$1,425	$0	-$24	-$2,683
53	Cust. Meter Read	$3,759,199		$3,033,733	$446,868	$75,898	$29,363	$55,799	$5,903	$247	$2,484	$13,249
54	Cust. Billing Other	$9,001,157		$7,308,461	$958,435	$163,240	$78,604	$164,940	$64,863	$2,834	$486	$28,299
55	Cust. Services & Info Ex.	$2,759,188		$1,599,654	$511,421	$86,861	$28,004	$53,216	$428,747	$10,773	$237	$14,402
56	Sales Expense	$548,968		$424,854	$25,810	$4,384	$9,232	$17,780	$57	$1	$41	$59,461
57	Total Customer	$37,801,765		$27,712,926	$5,732,343	$950,026	$530,521	$1,150,928	$668,631	$28,847	$5,361	$262,560

The Empire District Electric Company
Case No. ER-2014-0351
Test Year 12 Months Ending April 30, 2014
Updated through August 31, 2014
CCOS Summary

Line Number	Functional Category	Class Cost of Service	Allocator Number	Residential	CB	SH	TEB	GP	LP	SC-Praxair	PFM	Lighting
Total		$458,842,093		$227,768,915	$41,235,033	$10,616,748	$36,460,523	$77,348,142	$54,871,796	$3,728,312	$90,761	$6,721,859