Exhibit No.:	
Issue:	Customer Savings Plan
Witness:	Greg R. Meyer
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	MECG
Case No.:	EO-2018-0092
Date Testimony Prepared:	February 7, 2018

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Approval of its Customer Savings Plan.	**)** **)** **)** **)** **)** **)**	**Case No. EO-2018-0092**

Rebuttal Testimony of

Greg R. Meyer

On behalf of

Midwest Energy Consumers Group

February 7, 2018

BRUBAKER & ASSOCIATES, INC.

Project 10522

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Approval of its Customer Savings Plan.	))))))	**Case No. EO-2018-0092**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Greg R. Meyer

Greg R. Meyer, being first duly sworn, on his oath states:

1. My name is Greg R. Meyer. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Midwest Energy Consumers Group in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony which was prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. EO-2018-0092.

3. I hereby swear and affirm that the testimony is true and correct and that it shows the matters and things that it purports to show.

Greg R. Meyer

Subscribed and sworn to before me this 6th day of February, 2018.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2019
Commission # 15024862

Notary Public

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

In the Matter of the Application of The Empire District Electric Company for Approval of its Customer Savings Plan.	))))))	**Case No. EO-2018-0092**

Rebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Midwest Energy Consumers Group ("MECG"). These companies purchase substantial amounts of electricity from Empire District Electric Company ("Empire" or "Company") and the outcome of this proceeding will have an impact on their cost of electricity.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A The purpose of my rebuttal testimony is to provide MECG's conclusions regarding Empire's proposed Customer Savings Plan ("CSP"); present certain adjustments that should be considered in any decision to approve the CSP;[1] and to discuss the historical events associated with the Asbury Generating Plant.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A I will discuss the following topics in my rebuttal testimony:

- General Discussion of Empire's Customer Savings Plan
- Empire's Plans Analyzed
- Empire and Southwest Power Pool's ("SPP") Generation Profile
- A discussion of the Asbury Generating Plant including major capital projects completed at the plant since 2008.
- The calculation of the amount of the regulatory asset when any recovery is authorized.
- Treatment of Additional Equity infusions by the Tax Equity Partner.

Q AT THIS TIME, DO YOU RECOMMEND THAT THE COMMISSION APPROVE EMPIRE'S CSP?

A No. There are still several concerns the MECG has with the CSP. I will show that the benefits generated by the CSP in the first few years are relatively small. While Empire chooses to focus on the alleged total savings associated with the plan, most of those benefits are realized in years 11-20 of the study period. Recognizing that

[1] It is important to recognize that while I provide certain adjustments, in MECG's opinion, those adjustments are not sufficient to negate the potential harm and risk associated with the CSP.

much can change prior to that time, those alleged customer benefits are tenuous. Furthermore, implicit in Empire's calculation is the assumption of annual rate cases which are necessary in order to flow these benefits back to customers. Such an assumption is largely impractical. By reflecting a more reasonable rate case filing interval, the savings quantified by Empire are reduced. Finally, I would note that based on the issues raised by the Staff and the Office of Public Counsel in their rebuttal testimonies, my concerns could change.

General Discussion of Empire's Customer Savings Plan

Q PLEASE PROVIDE A BRIEF OVERVIEW OF EMPIRE'S CSP.

A Empire is proposing to change its generation fleet by adding 800 MW of wind generation to its existing operations. The 800 MW of wind will be located in or near Empire's service territory within the SPP. The investment in the 800 MW of wind will be in conjunction with a Tax Equity Partner which will invest between 50%-60% of the total cost of the project. In conjunction with the addition of this wind generation, Empire will retire its Asbury coal plant in April 2019.

Q HAS EMPIRE QUANTIFIED ANY SAVINGS ASSOCIATED WITH THE CSP?

A Yes. Empire estimates that the CSP will result in $334 million in savings to customers over a 20-year period.

Q YOU MENTIONED THAT THE ADDITION OF WIND GENERATION IS DONE IN CONJUNCTION WITH A TAX EQUITY PARTNER. PLEASE EXPLAIN THE IMPORTANCE OF THE TAX EQUITY PARTNER.

A The Empire CSP is premised on the savings that can be realized by Empire joining with a Tax Equity Partner that will help to finance the construction of the wind generation. Specifically, the Tax Equity Partner may be willing to finance as much as 50%-60% of the cost of the wind generation project.[2] The Tax Equity Partner is willing to provide this investment in exchange for the right to monetize the accelerated depreciation and Production Tax Credits ("PTCs") that the project will generate over time. After monetizing the depreciation and PTCs for some period of time, the Tax Equity Partner will exit the project and turn the wind investment over to Empire.

Q ARE YOU AWARE WHICH CONTRACTOR(S) WILL BE CONSTRUCTING THE 800 MW OF WIND?

A No. I am aware that an RFP has been issued seeking proposals for the siting and construction of the wind generation project. Furthermore, it is my understanding that responses have been received to the RFP. That said, it is also my understanding that the selection of the successful contractor(s) should be chosen sometime this month.

Q HAS THE TAX EQUITY PARTNER BEEN CHOSEN BY EMPIRE?

A No. It is my understanding that Empire hopes to have a Tax Equity Partner identified during the second quarter of 2018. While Empire has identified potential tax equity

[2]Empire has quantified the total cost of this project to be $1.5 billion – consisting of $1.4 billion associated with the construction of the wind farm and $100 million associated with transmission upgrades. Of this, the tax equity partner will provide up to $800 million.

providers including J.P. Morgan, Bank of America and Morgan Stanley, at this time there is no formal agreement to review between the potential Tax Equity Partner and Empire.

Q IS THERE A TIMEFRAME BY WHICH EMPIRE HAS REQUESTED THE COMMISSION APPROVE THE CSP? ALSO, PLEASE DESCRIBE THE IMPORTANCE OF THAT DATE ACCORDING TO EMPIRE.

A Empire is requesting Commission approval of its CSP by June 2018. The approval date corresponds with the time needed to meet certain environmental conditions at the Asbury coal plant if it is determined that the unit should continue operating. Additionally, it is my understanding that the approval is also designed to maximize the amount of PTCs generated by the project. Currently, the PTCs generated by such renewable projects are $24/MWh, but will be phased out by the end of 2020.

Q AT THE TIME OF THIS TESTIMONY FILING, THERE APPEARED TO BE CERTAIN OUTSTANDING ITEMS WHICH ARE CRITICAL TO THE CSP. PLEASE COMMENT.

A I agree there are several items which are still outstanding or unknown at the time of this testimony. As I described previously, we do not know who the Tax Equity Partner is and do not have any formal agreement to evaluate. We are not sure who will construct the additional 800 MW of wind. We are also not sure where this capacity will be located. Therefore, we are not certain of the level of transmission costs that will be needed to connect the wind project to the SPP market. It should be noted that the CSP has $100 million dedicated for transmission interconnection costs. Until the

location of the wind projects is known, one cannot determine if this value is reasonable.

Empire's Plans Analyzed

Q IN ORDER TO DEVELOP ITS CSP, DID EMPIRE EVALUATE DIFFERENT OPTIONS?

A Yes. Empire evaluated eight plans. Each plan was evaluated against Plan 5 from Empire's 2016 Integrated Resource Plan ("IRP"). This Plan 5, which constitutes Empire's current preferred resource plan, contemplates the ongoing operation of the Asbury plant as well as the acquisition of additional wind energy when current purchase power agreements expire. Additionally, Plan 5 includes the implementation of Realistic Achievable Potential ("RAP") Demand-Side Management ("DSM") projects.

Q PLEASE LIST EACH OF THE PLANS EMPIRE CONSIDERED.

A Table 1 presents the nine plans included in the analysis to formulate the CSP.

TABLE 1

Empire's Plans for Developing the CSP

Plan 1: Plan 5 from Empire's 2016 IRP plus RAP DSM
Plan 2: 800 MW of low Levelized Cost of Electricity ("LCOE") wind[3]
Plan 3: 400 MW of low LCOE wind; 400 MW of mid-LCOE wind
Plan 4: 800 MW of LCOE wind; retain Asbury plant
Plan 5: 800 MW of low LCOE wind; high fuel costs
Plan 6: 800 MW of low LCOE wind; low fuel costs
Plan 7: 300 MW of low LCOE wind; 300 MW of mid-LCOE wind
Plan 8: 200 MW of low LCOE wind; 200 MW of mid-LCOE wind
Plan 9: 200 MW of low LCOE wind; 200 MW of mid-LCOE wind, no solar

Q WHAT BASIS DID EMPIRE USE TO EVALUATE EACH OF THESE PLANS?

A Empire used a net present value of revenue requirements ("NPVRR") to evaluate each of these plans. The NPVRR is a present value calculation of the annual revenue requirements over the next 20 years. As such, the baseline for all comparisons is Empire's calculation that, under its preferred plan (Plan 5 from the 2016 IRP), the net present value revenue requirement will be $7,592 (in millions).

Q WHAT WERE THE RESULTS OF THE NPVRR FOR "THE NINE" PLANS?

A The NPVRR results showed that Plan 2 – 800 MW of LCOE wind – was the best option. Plan 2 is asserted to generate $334 million of savings as compared to the current preferred IRP plan. The plan totals also reflect the effects of the Tax Cut and Jobs Act of 2017 ("TCJA") which was enacted in January 2018. The impacts from tax reform were not available when Empire filed its direct testimony on October 31, 2017.

[3]Low levelized cost of electricity ("LCOE") is the lifetime costs of wind (construction and interconnection, operation and maintenance costs, capital upgrades and the cost of capital) divided by the total expected production. A low cost LCOE assumes the wind investment will achieve a high capacity factor, thus lowering the costs to customers. Conversely, a high LCOE represents the same levelized cost but applied to a lower wind capacity factor thus resulting in higher costs to customers.

Q PLEASE LIST THE NPVRR TOTALS FOR EACH PLAN.

A Table 2, below, lists the 20-year NPVRR by plan. These values include the effects from the TCJA.

TABLE 2

20-Year NPVRR by Plan

	20-Year NPVRR ($/Millions)
Plan 1: Plan 5 from Empire's 2016 IRP plus RAP DSM	$7,592
Plan 2: 800 MW of low Levelized Cost of Electricity ("LCOE") wind	$7,258
Plan 3: 400 MW of low LCOE wind; 400 MW of mid-LCOE wind	$7,334
Plan 4: 800 MW of LCOE wind; retain Asbury plant	$7,278
Plan 5: 800 MW of low LCOE wind; high fuel costs	$7,311
Plan 6: 800 MW of low LCOE wind; low fuel costs	$7,256
Plan 7: 300 MW of low LCOE wind; 300 MW of mid-LCOE wind	$7,387
Plan 8: 200 MW of low LCOE wind; 200 MW of mid-LCOE wind	$7,471
Plan 9: 200 MW of low LCOE wind; 200 MW of mid-LCOE wind, no solar	$7,474

Thus, pursuant to Empire's calculations, Plan 2 will result in savings of 4.4% as compared to the current preferred plan.

Q YOU INDICATED THAT TABLE 2 REFLECTS THE IMPACTS FROM THE TCJA. PLEASE PROVIDE A COMPARISON OF THOSE PLANS WITH AND WITHOUT THE TCJA.

A Table 3, below, shows the 20-year NPVRR effects from the TCJA.

TABLE 3

Comparison of Plans With/Without TCJA

	20-Year NPVRR No TCJA ($/Millions)	20-Year NPVRR With TCJA ($/Millions)
Plan 1: Plan 5 from Empire's 2016 IRP plus RAP DSM	$8,113	$7,592
Plan 2: 800 MW of low Levelized Cost of Electricity ("LCOE") wind	$7,788	$7,258
Plan 3: 400 MW of low LCOE wind; 400 MW of mid-LCOE wind	$7,941	$7,334
Plan 4: 800 MW of LCOE wind; retain Asbury plant	$7,814	$7,278
Plan 5: 800 MW of low LCOE wind; high fuel costs	$7,871	$7,311
Plan 6: 800 MW of low LCOE wind; low fuel costs	$7,785	$7,256
Plan 7: 300 MW of low LCOE wind; 300 MW of mid-LCOE wind	$7,970	$7,387
Plan 8: 200 MW of low LCOE wind; 200 MW of mid-LCOE wind	$8,032	$7,471
Plan 9: 200 MW of low LCOE wind; 200 MW of mid-LCOE wind, no solar	$8,037	$7,474

As Table 3 shows, the TCJA significantly reduces the 20-year NPVRR for all plans. The reduction in tax rates not only reduces the revenue requirements of Empire, but also reduces the level of investment from the Tax Equity Partner. As mentioned, the Tax Equity Partner is seeking to capture the value of accelerated depreciation and PTCs. These provide value by shielding income for the Tax Equity Partner. Given lower federal tax expense resulting from the reduction in the corporate tax rates, however, Tax Equity Partners have a lower amount of income tax exposure and will therefore not be as willing to invest as much into a project of this nature as it would have with a higher corporate tax rate.

Q YOU PREVIOUSLY MENTIONED THAT THE SAVINGS ASSOCIATED WITH PLAN 2 VERSUS THE CURRENT PREFERRED IRP PLAN WERE THIN IN THE FIRST SEVERAL YEARS OF THE STUDY PERIOD. CAN YOU SHOW THOSE SAVINGS BY FIVE-YEAR INCREMENTS FOR THE 20 YEAR PLANNING HORIZON?

A Yes. Table 4, below, presents the savings by five-year increments.

TABLE 4

Plan 2 – 800 MW of Wind, Retire Asbury Plant vs Plan 1 – 2016 Empire's IRP

Years	Cumulative NPVRR Dollars ($/Millions)
1-5	$ 28.3
6-10	$ 84.0
11-15	$188.2
16-20	$332.7

The above table clearly shows that the savings generated by Plan 2 over the first ten years are fairly small – only about 33% of the projected savings is anticipated to occur in the first ten years. The majority of the savings from Plan 2 do not occur until years 11-20 when the savings dramatically increase from $84 million to $333 million. Given the uncertainties prevalent in the electric industry, the fact that the majority of the savings occur in years 11-20 should be a concern.

Q WHAT ASSUMPTIONS ARE YOU REFERRING TO?

A One of the primary risks associated with Empire's projections is that market prices in the SPP market will decline as a result of the tremendous level of wind investments

currently in queue at SPP and planned to be placed in service in the near future. I will discuss the reasons for this concern later in my testimony.

The analysis is also based on annual revenue requirement filings with the Missouri Public Service Commission in order to return the savings to ratepayers. This is not a realistic assumption. By assuming less frequent rate cases, the savings identified above will be reduced. A more realistic rate case interval should be studied.

Q WHAT IS THE IMPACT ON THE SAVINGS ASSOCIATED WITH PLAN 2 IF EMPIRE FILES A RATE CASE EVERY TWO YEARS INSTEAD OF THE ANNUAL RATE CASES WHICH IS IMPLICIT IN THE CURRENT ANALYSIS?

A Table 5, below, shows the savings in five-year increments assuming both annual rate cases as well as a rate case every two years. Once again, the savings are very thin in the first ten years. This simple change to reflect a rate case every two years instead of annually, reduces the savings in the first ten years to only $38.9 million – or 13% of the total savings. Now, 87% of the savings are realized in years 11-20 when they are much more uncertain. Interestingly, with this small change, the status quo (2016 IRP) is more favorable than Plan 2 over the first five years. The savings in Plan 2 are not realized until the sixth year of the 20-year study horizon.

TABLE 5

Savings in Five-Year Increments

Years	Annual Rate Cases NPVRR Savings ($/Millions)	Biannual Rate Cases NPVRR Savings ($/Millions)
1-5	$ 28.3	($3.8)
6-10	$ 84.0	$38.9
11-15	$188.2	$152.6
16-20	$332.7	$300.6

Empire & SPP's Generation Mix

Q YOU INDICATED THAT THE CSP PROPOSES TO ADD 800 MW OF WIND TO EMPIRE'S GENERATION MIX. WITH THE ADDITION OF 800 MW OF WIND, AND THE RETIREMENT OF THE ASBURY COAL PLANT, WHAT WILL BE THE GENERATION MIX OF EMPIRE?

A Empire's existing generation mix is listed below in Table 6.

TABLE 6

Empire's Existing Generation Resources

Resource Name	Primary Fuel	Current Rating (MW)
Asbury	Coal	194
Iatan 1	Coal	85
Iatan 2	Coal	105
Plum Point (Owernship)	Coal	50
Riverton 10	Natural Gas	16
Riverton 11	Natural Gas	17
Riverton 12 Combined Cycle	Natural Gas	250
Energy Center 1	Natural Gas/Oil	82
Energy Center 2	Natural Gas/Oil	82
Energy Center 3	Natural Gas/Oil	49
Energy Center 4	Natural Gas/Oil	49
State Line 1	Natural Gas/Oil	94
State Line Combined Cycle	Natural Gas/Oil	297
Ozark Beach	Hydro	16
Plum Point EPA	Coal PPA	50
150 MW Elk River Wind Farm PPA	Wind PPA	17
105 MW Meridian Way Windfarm	Wind PPA	19

The above generation resources are broken down by generation resources in Table 7.

TABLE 7

Empire's Generation Type Resources

Generation Type	Current Rating (MW)	Percent of Total
Coal	434	29.5%
Natural Gas	283	19.2%
Natural Gas/Oil	653	44.4%
Hydro	16	1.1%
Coal PPA	50	3.4%
Wind PPA	36	2.4%
Total	1,472	100.0%

Empire's generation mix after adding 800 MW of wind and retiring the Asbury plant is listed below in Table 8.

TABLE 8
Empire's Generation Resources After CSP

Resource Name	Primary Fuel	Current Rating (MW)
Iatan 1	Coal	85
Iatan 2	Coal	105
Plum Point (Owernship)	Coal	50
Riverton 10	Natural Gas	16
Riverton 11	Natural Gas	17
Riverton 12 Combined Cycle	Natural Gas	250
Energy Center 1	Natural Gas/Oil	82
Energy Center 2	Natural Gas/Oil	82
Energy Center 3	Natural Gas/Oil	49
Energy Center 4	Natural Gas/Oil	49
State Line 1	Natural Gas/Oil	94
State Line Combined Cycle	Natural Gas/Oil	297
Ozark Beach	Hydro	16
Plum Point EPA	Coal PPA	50
150 MW Elk River Wind Farm PPA	Wind PPA	17
105 MW Meridian Way Windfarm	Wind PPA	19
New Wind – CSP		800

1 The above generation resources are broken down by generation resources in
2 Table 9.

TABLE 9
Empire's Generation Type Resources from CSP

Generation Type	Current Rating (MW)	Percent of Total
Coal	240	11.5%
Natural Gas	283	13.6%
Natural Gas/Oil	653	31.4%
Hydro	16	.8%
Coal PPA	50	2.4%
Wind PPA	36	1.7%
New Wind	800	38.5%
Total	2,078	100.0%

Table 9, above, shows the significant change in generation resources as a result of the CSP. Prior to the CSP, the percentage of coal generation for Empire was approximately 30%. After the CSP retirement of the Asbury plant, coal generation would account for just 12% of the total generation resources of Empire. Meanwhile, Empire's wind generation increases from 2.4% (two wind PPAs) to 38.5%.

Q EMPIRE IS A MEMBER OF THE SPP AND BIDS ITS GENERATION INTO THE SPP INTEGRATED MARKETPLACE ON A DAILY BASIS. WHAT IS THE CURRENT AND PROJECTED GENERATION RESOURCES FOR THE SPP?

A SPP's current generation mix is listed below in Table 10.

TABLE 10
2016 SPP Generation Mix

Generation Type	Current Rating (MW)	Percent of Total
Combined Cycle	9,852	11.4%
Hydro	4,552	5.3%
Internal Combustion	1,968	2.3%
Nuclear	2,447	2.8%
Other	560	.7%
Steam (coal)	39,973	46.4%
Wind	15,072	17.5%
Solar	275	.3%
Natural Gas	11,360	13.2%
Total	86,059	100.0%

SPP has also identified planned capacity additions which will significantly change the SPP generation mix. Table 11, below, shows the current generation levels, planned generation additions and the generation mix after these planned additions.

TABLE 11

2016 SPP Generation Mix and Planned Generation Additions

Generation Type	Current Rating (MW)	Planned Additions (MW)	Total Generation Mix	Percent of Total
Combined Cycle	9,852	0	9,852	8.5%
Hydro	4,552	60	4,612	4.0%
Internal Combustion	1,968	18	1,986	1.7%
Nuclear	2,447	0	2,447	2.1%
Other	560	1,400	1,960	1.7%
Steam	39,973	898	40,871	35.3%
Wind	15,072	26,166	41,238	35.6%
Solar	275	198	473	.4%
Natural Gas	11,360	915	12,275	10.6%
Total	86,059	29,655	115,714	100.0%

Table 11, above, clearly indicates that there will be a significant change in the generation mix at SPP if the planned additions are completed. The existing percentage of wind resources (17.5%) will more than double to 35.6%. As reflected in column 3, wind generation accounts for over 88% of the planned generation additions in SPP.

Q HAS THE CURRENT LEVEL OF WIND IN THE SPP MARKET RAISED CONCERNS THAT MAY AFFECT THE CSP?

A Yes. The current levels of wind in the SPP has caused a significant increase in negative prices. Negative prices result when there is more power in the market than is needed to serve the load. Generation that continues to produce power during negative price periods actually pay the SPP. Due to the presence of the PTCs, and recognizing that PTCs are paid on the basis of MWh's generated, owners of wind generation are willing to pay negative prices to SPP in order to maximize the value of the PTC. In the SPP State of the Market Fall 2017 report, a discussion of negative

prices in SPP is attributed to the prolific growth of wind generation in SPP. I have included Table 12 that shows the percentage of negative prices for the last three years.

TABLE 12
Negative Price Intervals – Real Time

Year	Percentage
2015	2.6%
2016	3.5%
2017*	7.0%

*Through November

As can be seen from Table 12, above, the percentage of negative price has more than doubled since 2015. In 2017, 7.0% of all hours, SPP experiences a negative price for electricity. Again, this is based upon a current SPP generation mix that only includes 17.5% wind generation. If the SPP adds 26,000 more MWs of wind and the generation mix of wind more than doubles, the possibility of an even greater increase in the number of hours in which negative prices are realized is virtually guaranteed.

Q IS THE SPP CONCERNED WITH THIS PROBLEM?

A Yes. In the State of the Market Fall 2017 report, SPP states that the growing frequency of negative prices indicates the potential need for changes in market rules. Either way then, whether negative market prices are permitted to become more common or whether there are changes in market rules, there is a great deal of uncertainty underlying the benefits of the CSP simply from Empire's participation in the SPP energy market.

Q ARE THERE OTHER CONCERNS WITH THE GROWTH OF WIND IN THE SPP MARKETPLACE BESIDES THE NEGATIVE PRICES?

A Yes. My previous discussion focused on the negative hourly price of electricity. The growth in negative hourly prices, however, may also signal that overall market prices have dropped with the growth of wind in SPP. If the projected wind additions are placed in service, a decrease in overall market prices may continue. Since market prices are a component justifying the CSP, decreased market prices could have a significant impact on the savings. The CSP is premised on the notion that enhanced wind sales in the SPP market will produce greater levels of revenues to offset the revenue requirements of Empire.

Asbury Plant History

Q PLEASE DESCRIBE THE ASBURY PLANT AND ITS RECENT CAPITAL ADDITIONS.

A The Asbury plant located near Asbury, Missouri, is a coal-fired generating unit with a current operating capacity of 194 MW. The Asbury plant was constructed in 1970 and, following the environmental improvements completed in 2014, was scheduled to retire in 2035.

In February 2008, a Selective Catalytic Reduction ("SCR") was constructed and placed in service at the Asbury plant. The cost of the SCR was approximately $31 million (excluding AFUDC).

In December 2014, Empire completed the installation of an environmental retrofit project. These environmental improvements were a result of Empire's preferred resource plan in the 2010 IRP. The project included the installation of a

pulse-jet fabric filter (baghouse), circulating dry scrubber and powder activated carbon injection system. The final cost was approximately $112 million, excluding AFUDC. The new system has operated a little over three years at the time this testimony was filed.

I have also included Table 13 that shows the growth in net plant since 2012 for the Asbury plant.

TABLE 13
Net Plant Growth at Asbury Plant
($000s)

Year	Plant In Service	Accumulated Reserve	Net Plant Balance
2012	$157,201	$46,683	$110,518
2013	$156,513	$48,252	$108,261
2014	$283,694	$36,803	$246,891
2015	$286,260	$45,225	$241,035
2016	$288,265	$56,282	$231,983
2017	$289,577	$64,424	$225,153

Source: MECG Data Request No. 5-1.

Table 13 illustrates the substantial growth in the net plant balance that occurred after the 2014 environmental retrofit was completed at the Asbury plant. These retrofits were deemed necessary to allow Asbury to stay in service until at least 2033.[4] However, a mere 3 years later customers are being informed that this plant must now be retired.

[4]Coal Age – Published Wednesday, September 2, 2015.

Q DO YOU BELIEVE CUSTOMERS SHOULD HAVE TO ABSORB THE FULL COST OF RETIREMENT OF THE ASBURY PLANT?

A No, I do not. I will discuss the ratemaking treatment that I would propose for retiring the Asbury plant in the next section of this testimony.

Asbury Plant Regulatory Asset Valuation and Cost Recovery

Q EMPIRE HAS REQUESTED THAT A REGULATORY ASSET BE ESTABLISHED FOR THE UNRECOVERED PORTION OF THE ASBURY PLANT AT THE TIME IT IS RETIRED. DO YOU HAVE ANY COMMENTS ON THIS ASPECT OF THE CSP?

A Yes. I have several comments on this area of the CSP. In the following section of my testimony I will discuss the following conditions applicable to the retirement of the Asbury plant. It should be noted that these conditions do not mean that I am endorsing the CSP plan to add wind and retire the Asbury plant.

- Clarification of the retirement of the Asbury plant from plant in service and the accumulated depreciation reserve.
- Proper valuation of the regulatory asset and rate base value for the regulatory asset.
- Deduction that should occur to the regulatory asset until Empire's next rate case.
- Suggested carrying cost on the regulatory asset included in rate base.

Q WHEN DOES EMPIRE PROPOSE TO RETIRE ASBURY UNDER THE CSP?

A Under the CSP, the Asbury plant is to be retired in April 2019. This retirement date is significantly sooner than its planned retirement in 2035 (2016 IRP).

Q IF THE ASBURY PLANT IS RETIRED IN APRIL 2019, WHAT IS YOUR RECOMMENDATION REGARDING THE RECORDING OF THAT RETIREMENT?

A At retirement, the original cost of the Asbury plant should be deducted from plant in service. Since a regulatory asset is proposed for the unrecovered plant investment, the accumulated depreciation reserve balance should be reduced by the accumulated reserve applicable to the Asbury plant. These adjustments retire the Asbury plant at net book value. Then a regulatory asset should be established for the net book value associated with retiring the Asbury plant.

I have read Empire's witness Sager's direct testimony and I believe we are in agreement with the recording of the retirement. (Sager Direct, page 2, lines 21 and 22)

Q SHOULD THE REGULATORY ASSET VALUE BE ADJUSTED BETWEEN THE TIME OF ASBURY'S RETIREMENT AND EMPIRE'S NEXT RATE CASE?

A Yes. Empire's current rates reflect both a return of the Asbury investment (depreciation) as well as a return on the Asbury investment. Simply because the unit is retired doesn't mean that this portion of Empire's rates are discontinued. Rather, Empire will continue to recover the depreciation and return on Asbury. I believe both the regulatory asset subject to amortization and the regulatory asset included in rate base should be adjusted to reflect this fact. Otherwise, Empire's regulatory asset will be overstated.

Q PLEASE DESCRIBE THOSE ADJUSTMENTS.

A First, I believe the regulatory asset for amortization and rate base should be reduced by the monthly amount of depreciation expense included in customer rates from

Empire's last general rate case (Case No. ER-2016-0023). This reduction would occur until the month when customer rates are changed from either a rate case or complaint case. In response to Staff Data Request No. 3-18, it appears Empire would support this proposal. Based on the Staff's Accounting Schedules in Empire's last rate case, annual depreciation for the Asbury plant was approximately $11.5 million (approximately $958,000 monthly). It should be noted that the depreciation value is a Missouri jurisdictional number. I believe it is imperative that the value of the regulatory asset properly reflect any depreciation collected by Empire from the point that Asbury is retired until new rates are established.

Second, in addition to depreciation, the Asbury plant is also providing a return (profit) in current rates. Again, Empire will continue to realize this return until the next rate case regardless of whether Asbury is retired. Any regulatory asset associated with the approval of the CSP, and the retirement of Asbury, should be reduced by the monthly return included in customer rates from Empire's last general rate case. Based on the Staff's Accounting Schedules from Empire's last general rate case, I have estimated the annual return on the Asbury plant to be worth $21.7 million ($1.81 million monthly). Once again, this value is a Missouri jurisdictional number.

Finally, I would recommend that the regulatory asset be reduced for the value of the excess deferred taxes associated with the TCJA.

Q WHAT ARE DEFERRED TAXES?

A Deferred taxes are the result of tax timing differences between a utility's regulatory books and tax books. These are primarily the result of accelerated depreciation that is provided for tax purposes, but not provided for regulatory purposes. The accelerated depreciation causes an income tax deduction for tax purposes that isn't

reflected in the regulatory calculation of income taxes. Therefore, ratepayers pay a higher amount of income taxes than the utility actually pays to the federal government. The result of this fact is called deferred taxes. Over the course of an asset's life, deferred taxes should eventually reverse. Specifically, over the early years, when income tax depreciation is higher, a deferred income tax is created. In later years, the regulatory deduction will be higher and the deferred income tax will reverse. At the end of an asset's useful life, the deferred income tax should be zero.

Q WHAT IS THE IMPACT OF THE TAX REFORM ACT ON DEFERRED TAXES?

A The TCJA reduced the federal tax rate from 35% to 21% for Empire. As a result, the taxes previously deferred at an effective federal tax rate of 35% will now be recognized at a 21% federal tax rate. This requires that the incremental tax change from 35% to 21% must be addressed. Since the Asbury plant will be retired, it is possible to use those excess deferred taxes as an offset to the regulatory asset immediately. I would propose that those excess taxes be used to immediately reduce the regulatory asset for amortization and rate base.

Q WHAT IS EMPIRE'S PROPOSED AMORTIZATION PERIOD FOR THE REGULATORY ASSET?

A Empire has requested a 30-year amortization period.

Q DO YOU HAVE A POSITION ON THE 30-YEAR AMORTIZATION PERIOD?

A Yes. I believe this period can be reduced as a result of my recommended carrying cost that should be applied to the regulatory asset.

Q WHAT CARRYING COST DO YOU RECOMMEND FOR APPLYING TO THE REGULATORY ASSET?

A I recommend that Empire's cost of long-term debt should be used to calculate the return on the regulatory asset.

Q WHAT IS THE RATIONALE FOR YOUR RECOMMENDATION THAT THE CARRYING COST ON THE REGULATORY ASSET BE THE LONG-TERM COST OF DEBT?

A My recommendation is based off of my previous testimony where I discussed the plant additions to the Asbury plant. The latest retrofit to the Asbury plant occurred in December 2014 costing over $112 million. Asbury's net plant balance increased by over $138 million in 2014. Those retrofits were intended to allow the Asbury plant to continue operations to at least 2033. However, just three years later, customers are being asked to allow Asbury to retire nearly 15 years before its anticipated retirement date. Given that ratepayers received such little benefit underlying the investment in Asbury environmental improvements, it seems inequitable to charge ratepayers the full weighted average cost of capital for the Asbury regulatory asset. Applying Empire's long-term interest rates to the regulatory asset seems to be a reasonable balance between the customers and shareholders of Empire.

Q IF INDEED THE PLANT WOULD HAVE ONLY BEEN PROJECTED TO REMAIN IN SERVICE UNTIL 2019, DO YOU BELIEVE EMPIRE WOULD HAVE MADE THE RETROFITS?

A No. In their annual reports to shareholders, on several occasions prior to the decision to build the retrofits, Empire discusses how the cost of renewable energy credits

("REC") would be the most cost-effective way to proceed. I have included a statement from Empire's 2008 Annual Report to Shareholders.

> When our SO_2 allowance bank is exhausted, we will need to purchase additional SO_2 allowances or build a Flue Gas Desulphurization (FGD) scrubber system at our Asbury Plant. Based on current and projected SO_2 allowance prices and high-level estimated FGD scrubber construction costs ($81 million in 2010 dollars), we expect it will be more economical for us to purchase SO_2 allowances than to build a scrubber at the Asbury Plant. We would expect the costs of SO_2 allowances to be fully recoverable in our rates.

Similar statements are found in Empire's 2009 and 2010 Annual Reports to Shareholders.

If Empire was aware that the Asbury plant would be retired a mere three years after the environmental improvements, the retrofit investments could have been avoided and the costs to customers would have been greatly reduced.

Q IN ORDER TO RETIRE THE ASBURY PLANT EARLY, EMPIRE WOULD HAVE HAD TO PROPOSE A CSP MUCH EARLIER. DID EMPIRE CONSIDER THE POSSIBILITY OF TAX EQUITY FINANCING IN THE CONTEXT OF ITS 2010 or 2013 IRPs?

A No. It is my understanding that while Empire considered wind generation in the context of its 2010 or 2013 IRPs, it did not consider the possibility of tax equity financing with that wind generation. As the current case demonstrates, the inclusion of the tax equity financing component significantly changes the economics of renewable energy projects. Had Empire properly considered tax equity financing, it is likely that Empire would have pursued additional wind generation instead of over $110 million of Asbury environmental improvements.

Q WAS EMPIRE AWARE EARLIER OF THE TAX EQUITY PARTNERSHIP IT NOW PROPOSES?

A Yes. In response to Data Request No. MECG 5-05, Empire lists cases it was aware of dating back ten years which involved tax equity financing for renewable generation projects. Clearly, tax equity financing was used in the industry at the time that Empire conducted its 2010 or 2013 IRPs. As such, Empire either knew or should have known of the advantages of tax equity financing. Nevertheless, it appears that Empire failed to properly consider this alternative. As a result, the decision to invest in $110 million of environmental improvements that Empire seeks to retire a mere three years later must be called into question.

Q HOW WOULD YOU RESPOND TO THE CRITICISM THAT YOU ARE PERFORMING A LOOK BACK IN ORDER TO CHANGE THE OUTCOME? IN OTHER WORDS, YOU ARE DOING A PERFECT HINDSIGHT REVIEW.

A I would not agree with that observation. I understand that a prudency review is based upon the information available to the utility at the time that it makes a particular decision. MECG is not seeking to use this docket to consider the prudency of the Asbury environmental improvements. I am not proposing, in this case, to change any of the decisions to retrofit Asbury; or the early retirement of Asbury in April 2019 if the CSP is approved. I am merely discussing the information that should have been considered at that time and how that information should be utilized in determining the impact on customers from the current docket. My discussion in this area is merely to support my recommendation for applying Empire's long-term debt rate, instead of the weighted average cost of capital, to the Asbury regulatory asset.

Q WHAT IS THE DIFFERENCE IN MAGNITUDE BETWEEN EMPIRE'S WEIGHTED AVERAGE COST OF CAPITAL AND ITS COST OF LONG-TERM DEBT?

A The difference in the savings analysis is 4.8%. The weighted average cost of capital (factored up for income taxes) in the savings analysis is 8.8% and the cost of long-term debt is 4%.

Additional Equity Infusion

Q DOES THE CSP ENVISION CERTAIN ADDITIONAL EQUITY INFUSIONS FROM THE TAX EQUITY PARTNER AFTER THE INITIAL INVESTMENT USED TO FINANCE THE CONSTRUCTION OF THE 800 MW OF WIND GENERATION?

A Yes. In the first nine years of the CSP, the Tax Equity Partner provides additional equity contributions to Empire.

Q WHAT DO THOSE CONTRIBUTIONS REPRESENT?

A It is my understanding that those tax equity contributions represent equity infusions to Empire to account for additional PTCs over and above the expected level of energy produced by the wind asset.

Q CAN YOU EXPLAIN HOW THOSE TAX EQUITY CONTRIBUTIONS ARE CALCULATED?

A Yes. Once the 800 MW of wind generation is constructed, an estimated annual production level of energy output will be established. The production threshold of 75% will then be applied against that level of production and the PTCs will accrue to the benefit of the Tax Equity Partner. Any wind generation in excess of the

production threshold (75% of total estimated production) will be multiplied by the current PTC rate of $24/MWh. This amount is then paid by the Tax Equity Partner to Empire and treated as an equity infusion.

Empire has reflected this new stream of revenues as a direct reduction to its annual revenue requirements.

Q DO YOU AGREE WITH THE PROPOSAL TO TREAT THE EXCESS PTC'S AS AN EQUITY INFUSION FOR EMPIRE?

A No. By allowing additional Tax Equity Partner contributions, Empire's customers will have to pay a return "on" and "of" those contributions. These contributions and their ratemaking treatment are no different than the initial investment the Tax Equity Partner made to assist on the construction of the wind projects.

By valuing the contributions only at the current PTC price of $24/MWh, Empire's customers are not receiving the full value of those PTCs. The correct value for revenue requirement purposes would be to increase the value of the PTC to reflect the revenue being covered by the effect of the tax credit. In this case, the PTC value of $24 would equate to a revenue requirement value of approximately $31.50/MWh.

In addition, the way Empire currently proposes to address the additional PTCs by reimbursing Empire at $24/MWh creates even less value. When Empire receives the contribution from the Tax Equity Partner at $24/MWh, it will be required to pay income taxes on that amount. This will only decrease the value of the PTCs more.

Q DO YOU HAVE AN ALTERNATIVE PROPOSAL?

A Yes. I believe that, rather than having the Tax Equity Partner monetize the excess PTCs, the additional PTCs generated above the threshold level should be transferred to Empire for its own use. In this way, Empire's customers would receive the entire benefit of the excess PTCs. If Empire finds that it cannot use all of the excess PTCs, it would be free to sell those PTCs to the Tax Equity Partner at $31.50/PTC. In this way, Empire's customers are correctly compensated for the PTCs.

Q WHAT IS YOUR RESPONSE TO THE ASSERTION THAT THOSE TAX EQUITY CONTRIBUTIONS ARE NECESSARY FOR THE TAX EQUITY PARTNER TO BE INVOLVED IN THE CSP FOR TEN YEARS.

A I realize my proposal may shorten the ten year time period for the Tax Equity Partner. If the Tax Equity Partner needs for the CSP to continue for its purposes for ten years, then it should contribute more in its upfront contribution. We should not be creating false contributions at the expense of Empire's customers to allow a Tax Equity Partner to remain in the CSP for ten years.

Conclusions and Recommendations

Q WOULD YOU SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A My conclusions and recommendations are listed below:

- I recommend that the Commission not approve Empire's CSP. As demonstrated, the alleged customer benefits are overstated by an implicit assumption of annual rate cases. Moreover, the benefits are tenuous given the current and planned additions of wind in the SPP marketplace. The increasing prevalence of wind in SPP will lead to a higher frequency of negative market prices that would have a tremendous impact on potential future benefits.

- In the event that the Commission does approve the CSP, I recommend that the regulatory asset from the retirement of the Asbury plant be reduced from the effects of depreciation, return on investment and excess deferred income taxes. I also recommend that the Commission establish a carrying cost equal to Empire's cost of long term debt.

- I am concerned about the prolific growth of wind generation in SPP and its effects on market prices included as a revenue requirement offset in the CSP.

- I recommend that excess PTCs above the threshold production level be transferred to Empire for either its own use or for sale back to the Tax Equity Partner at its correct market value.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Qualifications of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from the University of Missouri in 1979 with a Bachelor of Science Degree in Business Administration, with a major in Accounting. Subsequent to graduation I was employed by the Missouri Public Service Commission. I was employed with the Commission from July 1, 1979 until May 31, 2008.

I began my employment at the Missouri Public Service Commission as a Junior Auditor. During my employment at the Commission, I was promoted to higher auditing classifications. My final position at the Commission was an Auditor V, which I held for approximately ten years.

As an Auditor V, I conducted audits and examinations of the accounts, books, records and reports of jurisdictional utilities. I also aided in the planning of audits and investigations, including staffing decisions, and in the development of staff positions in which the Auditing Department was assigned. I served as Lead Auditor and/or Case

Supervisor as assigned. I assisted in the technical training of other auditors, which included the preparation of auditors' workpapers, oral and written testimony.

During my career at the Missouri Public Service Commission, I presented testimony in numerous electric, gas, telephone and water and sewer rate cases. In addition, I was involved in cases regarding service territory transfers. In the context of those cases listed above, I presented testimony on all conventional ratemaking principles related to a utility's revenue requirement. During the last three years of my employment with the Commission, I was involved in developing transmission policy for the Southwest Power Pool as a member of the Cost Allocation Working Group.

In June of 2008, I joined the firm of Brubaker & Associates, Inc. as a Consultant. Since joining the firm, I have presented testimony and/or testified in the state jurisdictions of Florida, Idaho, Illinois, Indiana, Maryland, Missouri and Washington. I have also appeared and presented testimony in Alberta and Nova Scotia, Canada. These cases involved addressing conventional ratemaking principles focusing on the utility's revenue requirement. The firm Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients including industrial and institutional customers, some utilities and, on occasion, state regulatory agencies.

More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate, feasibility, economic, and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services, and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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