Cases with Filed Written Testimony of Todd W. Tarter

Before the Missouri Public Service Commission

- Rate Cases

ER-2006-0315, ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345, ER-2014-0351

- Fuel Adjustment Cases

ER-2011-0320, ER-2012-0098, ER-2012-0326, ER-2013-0122, ER-2013-0442, ER-2014-0087, ER-2014-0264, ER-2015-0085, ER-2015-0247, ER-2016-0080

- Fuel Adjustment True-Up

EO-2014-0088, EO-2014-0265, EO-2015-0086, EO-2015-0248, ER-2016-0082

Before the Kansas Corporation Commission

- Rate Docket

05-EPDE-980-RTS

- Energy Cost Adjustment ACA Docket

KS-12-EPDE-392-ACA, KS-13-EPDE-385-ACA, KS-14-EPDE-270-ACA

Before the Oklahoma Corporation Commission

- Rate Cause

PUD 201100082

- Fuel Prudence Review Causes

PUD 201100131, PUD 201200170, PUD 201300131, PUD201400226, PUD201500265

- Energy Efficiency Cause

PUD 201300142, PUD 201300203

Before the Arkansas Public Service Commission

- Energy Efficiency Docket

07-076-TF

- Net Metering Docket

12-060-R

- Rate Docket

13-11-U

SCHEDULE TWT-2

EXEMPLARY NOTICE

On October x, 2015 The Empire District Electric Company filed revised electric service tariff sheets with the Missouri Public Service Commission (PSC) which would increase the Company's Missouri jurisdictional annual gross revenues by $33.4 million or approximately 7.3 percent. For a residential customer using 1,000 kilowatt-hours of electricity a month, the proposed increase would be approximately $12.54 each month.

The Company is also asking to continue the use of the Fuel Adjustment Clause (FAC) with an updated base cost of energy. The difference between actually incurred fuel costs and base cost will be billed or credited to each customer based on the customer's monthly energy usage. The continuation of the FAC will allow the Company to adjust customers' bills twice each year, on June 1st and December 1st, based on the varying costs of fuel used to generate electricity at the Company's generating units and electric energy the Company purchases on behalf of its customers.

Local public hearings have been set before the PSC as follows:

dates, times, locations

.

Each public hearing will begin with a question-and-answer session

If you wish to comment or secure information, you may contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone (866) 922-2959, email opcservice@ded.mo.gov or the Missouri Public Service Commission, Post Office Box 360 Jefferson City, Missouri 65102, telephone 800-392-4211,email pscinfo@psc.mo.gov.

The Commission will also conduct an evidentiary hearing at its offices in Jefferson City during the weeks of (month) (day) through (month) (day), and (month) (day) through (month) (day), beginning at 8:30 a.m.

The hearings and local public hearings will be held in buildings that meet accessibility standards required by the Americans with Disabilities Act. If a customer needs additional accommodations to participate in these hearings, please call the Public Service Commission's Hotline at 1-800-392-4211 (voice) or Relay Missouri at 711 prior to the hearing.

SCHEDULE TWT-3

1 Date Mailed: 08/09/15
Account Number: 000011-11-0

TOTAL AMOUNT DUE	**$130.00**
Delinquent after 08/29/15, add late fee of	$0.65
After 08/29/15, Pay	$130.65
TOTAL AMOUNT ENCLOSED	$

2 JOHN A. CUSTOMER
101 MAIN STREET
ANYWHERE, MO 11111

Remit to:
3 EMPIRE DISTRICT
PO BOX 219239
KANSAS CITY, MO 64121-9239

129482039400000088000000000088441

For account questions, call 800-206-2300. To pay your bill by phone, call 888-631-8973.

Empire District (www.empiredistrict.com)
602 S. Joplin Avenue
Joplin, MO 64801-2337

4 **Account Number: 000011-11-0**

Summary as of 08/08/15:

5	Previous Bill	07/10/15		$130.00
	Payment Received	07/10/15	Check	($130.00) Thank you
	Balance Forward			$0.00
	Electric		000011-11-001	$130.00 ***
6	**TOTAL AMOUNT DUE**			**$130.00**

****** see Account Detail following message(s).***

7 If you have a question or problem with billing or service or need help managing your charges with a delayed payment agreement, we welcome your call or visit to your local office. The address and toll-free number are shown above.

You may pay your bill by credit or debit card by calling 888-631-8973 or online at www.empiredistrict.com. Select the Customer Service tab and Payment Information. There is a convenience fee for this service.

1) Nine-digit account number needed to make a payment.
2) Customer and billing location information.
3) Empire's mailing address to remit payment. Information on additional payment methods can be found on Empire's Web site, www.empiredistrict.com.
4) Customer account number.
5) Previous balance, recent payments, and remaining balance.
6) Total amount due for current month – detailed explanation on customer charges can be found on the back of the bill.
7) This area has important messages from Empire District.

Account Detail

8 **Electric 000011-11-001**	9 For Service at 101 Main Street, Anywhere, MO 11111		Rate: RG-Residential	
10 Read for: 00118237 From 07/08/15 to 08/06/15 (29 Days), Curr Read - 13701 Prev Read - 12701. Totaling 1,000 KwH				
11 08/08/15	Customer Charge	1 x 12.52	$12.52	
12 08/08/15	Usage Charge	600KWH x .12254	$73.52	
08/08/15	Usage Charge	400KWH x .09961	$39.84	
13 08/08/15	Energy Efficiency Program Cost	1000KWH x .00027	$0.27	
14 08/08/15	Fuel Adjust Charge	1000KWH x .00021	$0.21	
15 08/08/15	Anywhere County Tax	111.18 x .00875	$0.97	
		16 **Current Months Charges:**	**$127.33**	
08/08/15	17 APP Installment			$130.00
		18 **Billed Charges:**		**$130.00**

Contract Update

APP 19 Status before payment is $127.33, after payment in full $2.67. This account will be reevaluated in June.

8) 11-digit location number to report outages or to use automated account information by phone.

9) Service address - this is important for customers who have multiple accounts with Empire.

10) Meter number, previous meter read, current meter read, and usage information.

11) Empire service includes a fixed monthly customer charge, no matter how much electricity is used.

12) The usage charge is for the kilowatt hours (KWH) used by a customer. The charge for each KWH used by a customer from June 16 through September 16 is $0.12254 per KWH. The charge for electricity for the other eight months of each year is $0.12254 per KWH for the first 600KWH and $0.09961 for each KWH thereafter.

13) The cost to provide programs for customers to improve the energy efficiency of their homes and businesses.

14) The charge for the difference between fuel and purchased power costs established in the current rate structure and the actual fuel and purchased power costs incurred by Empire. This rate changes twice a year. If fuel costs are less than what is established by the current rates, customers will see a credit in the Fuel Charge line. The cost includes no mark-up or profit for Empire.

15) Taxes, fees, and other assessments.

16) Total charges for the billing period.

17) APP, average payment plan, is a payment contract that calculates a customer's expected annual usage and divides it into 12 equal payments. Each month one payment installment is due from the customer. At the end of 12 months the actual usage is reviewed and a customer's contract and installments are adjusted for the next 12 months.

18) The amount due from the customer by the due date.

19) Important information about a customer's payment contract.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4		Original Sheet No. 17u
Canceling P.S.C. Mo. No.		Sec.			Original Sheet No.

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after xxxx xx, 2016

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	**Filing Dates**	**Recovery Periods**
September–February	By April 1	June–November
March–August	By October 1	December–May

The Company will make a Fuel Adjustment Rate ("FAR") filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

RECOVERY PERIOD:
The billing months during which a FAR is applied to retail customer usage on a per kilowatt-hour (kWh) basis.

BASE ENERGY COST:
Base energy cost is ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA").

BASE FACTOR ("BF"):
The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.02688 per kWh for each accumulation period.

THE EMPIRE DISTRICT ELECTRIC COMPANY

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RIDER FAC
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APPLICATION

FUEL & PURCHASE POWER ADJUSTMENT

$$FPA = \{[(FC + PP + E - OSSR - REC - B) * J] * 0.95\} + T + I + P$$

Where:

FC = Fuel Costs Incurred to Support Sales:

The following costs reflected in Federal Energy Regulatory Commission (FERC) Accounts 501 and 506: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, and bio-fuel), fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments assessed by coal suppliers, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs , combustion product disposal revenues and expenses, consumable costs related to Air Quality Control Systems (AQCS) operation, such as ammonia, lime, limestone, and powdered activated carbon, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

The following costs reflected in FERC Accounts 547 and 548: natural gas generation costs related to commodity, oil, transportation, , fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees.

PP = Purchased Power Costs:

1. Costs and revenues for purchased power reflected in FERC Accounts 555 , excluding all charges under Southwest Power Pool (“SPP”) Schedules 1a and 12. Such costs and revenues include: purchased power costs, purchased power demand costs associated with purchased power contracts with a duration of one year or less, settlements, insurance recoveries, and subrogation recoveries for purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, broker commissions, fees and margins and SPP energy market charges including:

DATE OF ISSUE October 16, 2015 DATE EFFECTIVE November 15, 2015
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

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RIDER FAC
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A. SPP costs or revenues for SPP's energy and operating market settlement charge types and market settlement clearing costs or revenues including:

i. Energy;
ii. Ancillary Services;
   a. Regulating Reserve Service
   b. Energy Imbalance Service
   c. Spinning Reserve Service
   d. Supplemental Reserve Service
iii. Revenue Sufficiency;
iv. Losses;
v. Revenue Neutrality;
vi. Congestion Management including;
   a. Congestion
   b. Transmission Congestion Rights
   c. Financial Transmission Rights
vii. Demand Reduction;
viii. Grandfathered Agreements;
ix. Virtual Transaction Fee;
x. Pseudo-tie;
xi. Miscellaneous;

B. Non-SPP costs or revenue as follows:

i. If received from a centrally administered market (e.g. PJM / MISO), costs or revenues of an equivalent nature to those identified for the SPP costs or revenues specified in sub part A of part 1 above;
ii. If not received from a centrally administered market:
   a. Costs for purchases of energy; and
   b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and
   c. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy short fall and for a duration up to the expected length of the period during which the shortfall is expected to exist;

2. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles; and

3. Thirty-four percent of SPP transmission service costs reflected in FERC Account 565, excluding SPP Schedule 1a and Schedule 12 and 50% of Non-SPP transmission service costs reflected in Account 565. Such transmission service costs include:

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For ALL TERRITORY

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A. SPP costs associated with Net Integration Transmission Service:

i. SPP Schedule 11 – Base Plan Zonal Charge and Region-wide Charge;
ii. SPP Schedule 7 – Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service:
iii. SPP Schedule 8 – Non-Firm Point-To-Point Transmission Service;
iv. SPP Schedule 2 – Reactive Supply and Voltage Control from Generation or Other Sources Service; and
v. SPP Schedule 3 – Regulation and Frequency Response Service.

B. Non-SPP costs associated with:

i. Network transmission service;
ii. Point-to-point transmission service;
iii. System control and dispatch; and
iv. Reactive supply and voltage control.

4. Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another market participant implement a new charge type, exclusive of changes in transmission revenue, not listed in Exhibit 3**, "**List of Sub-Accounts Included and Excluded for FAC" of the Non-Unanimous Stipulation and Agreement on Certain Issues in Case No. ER-2014-0351:

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party's right to challenge the inclusion as outlined in E. below;

B. The Company will make a filing with the Commission giving the Commission notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such new charge type cost or revenue, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues;

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E. If the Company makes the filing provided for by B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that

party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. A party wishing to challenge the inclusion of a charge type shall include in its filing the reasons why it believes the Company did not show that the new charge type possesses the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

F. A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such new charge type cost or revenue, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after xxxx xx, 2016

E = Net Emission Costs:

The following costs and revenues reflected in FERC Accounts 509, 411.8 and 411.9 (or any other account FERC may designate for emissions expense in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging.

OSSR = Revenue from Off-System Sales (Excluding revenue from full and partial requirements sales to municipalities):

The following revenues or costs reflected in FERC Account 447: all revenues from off-system sales, including capacity charges associated with sales contracts shorter than 1 year, and SPP energy and operating market revenues, including but not limited to the following: (see Note A. below)

- i. Energy;
- ii. Ancillary Services including;
  - a. Regulating Reserve Service
  - b. Energy Imbalance Service
  - c. Spinning Reserve Service
  - d. Supplemental Reserve Service
- iii. Revenue Sufficiency;
- iv. Losses;
- v. Revenue Neutrality;
- vi. Demand Reduction;
- vii. Grandfathered Agreements;
- viii. Pseudo-tie;
- ix. Miscellaneous;
- x. Hedging.

REC = Renewable Energy Credit Revenue:

Revenues reflected in FERC Account 456 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

HEDGING COSTS:

Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the-counter or exchanged traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars and swaps.

Note A Should FERC require any item covered by factors FC, PP, E, REC or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E, REC or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after xxxx xx, 2016

number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = Net base energy cost is calculated as follows:

$B = (S_{AP} * \$0.02688)$

S_{AP} = Actual net system input at the generation level for the accumulation period.

J = $\frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$

Where Total system kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

I = Interest applicable to (i) the difference between Total energy cost (FC + PP + E – OSSR – REC) and Net base energy costs (“B”) multiplied by the Missouri energy ratio (“J”) for all kWh of energy supplied during an AP until those costs have been billed; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

FUEL ADJUSTMENT RATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest \$0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and secondary voltage by multiplying the average cost at the generator by 1.0466 and 1.0662, respectively. Any FAR authorized by the Commission shall be billed based upon customers’ energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below

$$FAR = \frac{FPA}{S_{RP}}$$

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Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period.

$$= \text{Forecasted total system NSI} * \frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$$

Where Forecasted total system NSI kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

PRUDENCE REVIEW

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

TRUE-UP OF FPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing with an adjustment to its FAC on the first Filing Date that occurs after completion of each Recovery Period. The true-up adjustment shall be the difference between the FPA revenues billed and the FPA revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T above and shall include interest calculated as provided for in item I above.

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For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after xxxx xx, 2016

	Accumulation Period Ending		
1	Total Energy Cost (TEC) = (FC + PP + E – OSSR - REC)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		$0.02688
	2.2 Accumulation Period NSI (S_{AP})		
3	(TEC-B)		
4	Missouri Energy Ratio (J)	*	
5	(TEC - B) * J		
6	Fuel Cost Recovery	*	
7	(TEC - B) * J * 0.95		
8	True-Up Amount (T)	+	
9	Prudence Adjustment Amount (P)	+	
10	Interest (I)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
12	Forecasted Missouri NSI (S_{RP})	÷	
13	Current Period Fuel Adjustment Rate (FAR) to be applied Beginning July 17, 2015	=	
14	Current Period FAR_{PRIM} = FAR x VAF_{PRIM}		
15	Current Period FAR_{SEC} = FAR x VAF_{SEC}		
16	VAF_{PRIM} = 1.0466		1.0466
17	VAF_{SEC} = 1.0622		1.0622

DATE OF ISSUE October 16, 2015 DATE EFFECTIVE November 15, 2015
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FC	501 & 506	
#	Description	Accounts
1	Coal Commodity and railroad transportation	501042, 501400, 501401, 501601, 501604, 501605
2	switching and demurrage charges	501042
3	applicable taxes	501042
4	natural gas costs	501054
5	alternative fuels	501300
6	fuel additives	501042
7	Btu adjustments assessed by coal suppliers	501042
8	Quality adjustments assessed by coal suppliers	501042
9	Fuel hedging costs	501211, 501212, 501216
10	fuel adjustments included in commodity and transportation costs	501042
11	broker commissions and fees associated with price hedges	501607
12	oil costs	501045
13	propane costs	
14	combustion product disposal revenues and expenses	501183
15	consumables related to AQCS (ammonia, lime, limestone, powder activated carbon, urea, sodium bicarbonate, & trona)	506127, 506128, 506129, 506201, 506202, 506203, 506204, 506210
16	settlement proceeds	
17	insurance recoveries	
18	subrogation recoveries for increased fuel expenses in Account(s) 501	

FC	547 & 548	
#	Description	Accounts
1	Natural gas generation costs related to commodity	547205, 547206, 547207, 547208, 547210, 547605, 547606
2	oil	547213
3	transportation	547210
4	storage	547210
5	capacity reservation	547210
6	fuel losses	547210
7	hedging costs for natural gas	547211, 547212, 547301
8	oil	547213
9	natural gas used to cross-hedge purchased power	
10	fuel additives/consumables	548202, 548216
11	settlement proceeds	
12	insurance recoveries	
13	subrogation recoveries for increase fuel expenses	
14	broker commissions	547607
15	fees and revenues and expenses resulting from fuel and transportation portfolio optimization activities	

PP		555, 565, 457	
#		Description	Accounts
1		Purchased Power costs	555430
2		PPA demand (capacity) cost (< 1 Year PPA)	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
3		settlements	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
4		insurance recoveries	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
5			
6		subrogation recoveries for purchased power expenses	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
7		virtual energy charges	555820, 555920
8		generating unit price adjustments	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
9		load/export charges	555910, 555810
10		energy position charges	555800, 555900
11		ancillary services including penalty & distribution charges	555840, 555850, 555860, 555870, 555940, 555950, 555960, 555970
12		broker commissions	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
13		fees and margins	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
14		SPP energy marketing charges including but not limited to:	
	14a	Energy	555800, 555810, 555820, 555900, 555910, 555920
	14b	Ancillary Services	555840, 555850, 555860, 555870, 555940, 555950, 555960, 555970
	14c	Revenue Sufficiency	555880
	14d	Losses	Losses are now handled through the market and are a component of the LMP which will be reflected in the Energy (555800-555820 & 555900-555920)
	14e	Revenue Neutrality	555880
	14f	Congestion Management	555990, 555995
	14g	Demand Reduction	555880
	14h	Grandfathered Agreements	555880
	14i	Virtual Transaction Fee	555880
	14j	Psuedo Tie	555980
	14k	Miscellaneous	555980
15		Non-Spp costs/revenues (MISO, PJM, etc)	555430
16		Costs not received from centrally administrated market including:	
	16a	Costs for purchases of energy	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
	16b	Costs for purchases of generation capacity (< 1 year)	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
	16c		
17		SPP NITS service Charges (Schd 11)	565414, 457141, 457142
18		SPP Point-to-point revenue	
	18a	Schedule 7 - Firm PTP	457137
	18b	Schedule 8 Non-firm PTP	457138
	18c	Schedule 1 Sc	457160
19		Schedule 1a - SPP Tariff Administration	565414
20		SPP Schedule 12 - FERC Assesssment	565415
21		Non SPP costs/revenues associated with:	
	21a	Network transmission service	
	21b	Point-to-point transmission	565416
	21c	System control & dispatch	565416
	21d	Reactive supply & voltage control	565416

E		509, 411	
#		411	Accounts
1		Net Emission Allowances	411800

OSSR		447	
#		411	Accounts
1		Revenue from off-system sales	447113, 447124, 447133, 447143, 447810, 447820, 447830, 447840

REC		456	
#		411	Accounts
1		Renewable Energy Credit Revenue	456071, 456072, 456073, 456074

Accounts and Definitions from Empire's Existing and Proposed FAC

GL	Descriptions	Details
501042	Fuel - Coal	Coal costs used in steam generation - includes coal, freight, railcar lease, property tax on railcars, railroad maintenance (material and labor), railcar maintenance, coal handling costs (equipment, repairs, fuel, labor)
501045	Fuel - Oil	Oil costs used in steam generation - includes oil, freight, handling costs
501054	Fuel - Natural Gas	Natural gas costs used in steam generation - includes gas, pipeline transportation cost
501183	Sales Of Ash	Proceeds form the sale of coal ash
501211	Ineffect (Gain)Loss Deri Steam	Ineffective gain/loss on FAS133 derivatives for steam generation - **currently not used**
501212	Effective (Gn)Less Deriv Steam	Effective gain/loss on FAS133 derivatives for steam generation - **currently not used**
501216	NonFAS133Deriv(Gain)/LossSteam	Gain/loss on Non-FAS133 derivatives for steam generation
501300	Fuel - Tires	Tire costs used in steam generation
501400	Ops Labor-Fuel Handling	Fuel Handling labor costs - Plum Point
501401	Ops Mtls-Fuel Handling	Fuel Handling materials costs - Plum Point
501601	Fuel Administration - Asbury	Misc fuel costs steam generation - Asbury - **not included in fuel adjustment**
501604	Fuel Administration - Riverton	Misc fuel costs steam generation- Riverton - **not included in fuel adjustment**
501605	Fuel Administration Plum Point	Misc fuel costs steam generation - Plum Point - **not included in fuel adjustment**
501607	Fuel Adm E Trader Commission	Commission expense for derivatives for steam generation - **currently not used**
547205	Natural Gas SLCC Tolling	Natural gas costs used in combustion turbine generation - SLCC Tolling - **currently not used**
547206	Nat Gas-Tollng SLCC Ineffectiv	Ineffective gain/loss on FAS133 derivatives for combustion turbine generation - SLCC Tolling - **currently not used**
547207	Nat Gas-Tolling SLCC Effective	Effective gain/loss on FAS133 derivatives for combustion turbine generation - SLCC Tolling - **currently not used**
547208	Comb Turb Fuel Sales - Nat Gas	Sales of natural gas
547210	Combust Turb Fuel Natural Gas	Natural gas costs used in steam generation - includes gas, pipeline transportation cost
547211	Ineffect (Gain)Loss Deriv Gas	Ineffective gain/loss on FAS133 derivatives for combustion turbine generation - **currently not used**
547212	Effective (Gain)Loss Deriv Gas	Effective gain/loss on FAS133 derivatives for combustion turbine generation - **currently not used**
547213	Fuel - No 2 Oil Fuel	Oil costs used in combustion turbine generation
547301	NonFAS133 Deriv (Gain)/Loss	Gain/loss on Non-FAS133 derivatives for combustion turbine generation
547605	Fuel Adm State Line	Misc fuel costs combustion turbine generation - State Line - **not included in fuel adjustment**
547606	Fuel Adm Energy Center	Misc fuel costs combustion turbine generation - Energy Center -**not included in fuel adjustment**
547607	Fuel Adm E Traders Commission	Commission expense for derivatives for combustion turbine generation - **currently not used**
411800	Gains-Disposition Emmiss Allow	Gain on disposition of Emission Allowances
456071	Misc Elec Rev-Green Credits-AR	Revenue for sale of Renewable Energy Credits -allocated to Arkansas
456072	Misc Elec Rev-Green Credits-KS	Revenue for sale of Renewable Energy Credits -allocated to Kansas
456073	Misc Elec Rev-Green Credits-MO	Revenue for sale of Renewable Energy Credits -allocated to Missouri
456074	Misc Elec Rev-Green Credits-OK	Revenue for sale of Renewable Energy Credits -allocated to Oklahoma
506127	Limestone Expense - Iatan	AQCS limestone expense - Iatan
506128	Powdered Activated Carbon	AQCS powdered activated carbon expense
506129	Ammonia Expense	AQCS ammonia expense
506201	Limestone Expense	AQCS limestone expense - Iatan
506202	Ammonia Expense	AQCS ammonia expense
506203	Powdered Activated Carbon	AQCS powdered activated carbon expense - Iatan
506204	Limestone Expense	AQCS limestone expense - Plum Point
506210	AQCS Construct Acctg Iatan 2	
548202	Ammonia Expense	AQCS ammonia expense - SLCC
548216	Gener Exp-Water Injection Sys	
447113	Gen Ark Off-Sys Sale-Resale	Off-System Sales of energy - allocated to Arkansas - **currently not used**
447124	Gen Ks Off-System Sale-Resale	Off-System Sales of energy - allocated to Kansas - **currently not used**
447133	Gen Mo Off-Sys Sale-Resale	Off-System Sales of energy - allocated to Missouri - **currently not used**
447143	Gen Ok Off-Sys Sales-Resale	Off-System Sales of energy - allocated to Oklahoma - **currently not used**
447860	Bilateral Sales	Off-System Sales of energy - allocated to Oklahoma
555430	Direct Purchases	Long-term PPA's, MISO congestion and losses, AECI Line losses, MISO Inadvertent, MISO Schedule 24, MISO ARR Distribution, MISO ARR Transaction, MISO Miscellaneous

555800	DA Asset Energy	Net Day Ahead Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Day Ahead Market energy position at an Asset Owner's resources and loads.	Integrated Market energy charge types performed on an hourly basis for each operating day and based on the results of the Day Ahead Market clearing.
555810	DA Non-Asset Energy	Net Day Ahead Non Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Day Ahead Market energy position at interchange locations into and out of SPP footprint.	
555820	DA Virtual Energy	Net Day Ahead Virtual Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Day Ahead Market energy position of cleared virtual transactions, financial only now mwhs.	
555840	DA Reg-Up	Net Day Ahead Regulation-Up Amount & Day Ahead Regulation-Up Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Up cleared to an asset owner's zonal obligation.	Integrated Market operating reserve charge types, these help to ensure reliability within the market. Regulation-up and regulation-down maintain the balance between load and generation. Spinning and supplemental are available in the event of outages.
555850	DA Reg-Down	Net Day Ahead Regulation-Down Amount & Day Ahead Regulation-Down Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Down cleared to an asset owner's zonal obligation.	
555860	DA Spinning	Net Day Ahead Spinning Amount & Day Ahead Spinning Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Spinning cleared to an asset owner's zonal obligation.	
555870	DA Supplemental	Net Day Ahead Supplemental Amount & Day Ahead Supplemental Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Supplemental cleared to an asset owner's zonal obligation.	
555880	DA Other	Other Day Ahead charges that settle at the EDE EDE Load node including: DA Make Whole Payment (MWP), DA MWP Distribution, DA Over-collected losses Distribution Amount, DA Demand Reduction (DR), DA DR Distribution Amount, DA Grandfathered Agreement (GFA) Carve-Out Daily, DA GFA Carve-Out Monthly, DA GFA Carve-Out Yearly, GFA Carve-Out Distribution Daily Amount, GFA Carve-Out Distribution Monthly Amount, GFA Carve-Out Distribution Yearly Amount, DA Virtual Transaction Fee Amount	See Below
555900	RT Asset Energy	Net Real Time Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Real Time Market energy position at an Asset Owner's resources and loads.	Integrated Market energy charge types performed on a dispatch interval basis (5 minutes)for each operating day and are based on the difference between the results of the Real Time Balancing Market process and the Day Ahead Market Clearing..
555910	RT Non-Asset Energy	Net Real Time Non Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Real Time Market energy position at interchange locations into and out of SPP footprint.	
555920	RT Virtual Energy	Net Real Time Virtual Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Real Time Market energy position of cleared virtual transactions, financial only now mwhs.	
555940	RT Reg-Up	Net Real Time Regulation-Up Amount & Real Time Regulation-Up Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Up cleared to an asset owner's zonal obligation.	Integrated Market operating reserve charge types, these help to ensure reliability within the market. Regulation-up and regulation-down maintain the balance between load and generation. Spinning and supplemental are available in the event of outages.
555950	RT Reg-Down	Net Real Time Regulation-Down Amount & Real Time Regulation-Down Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Down cleared to an asset owner's zonal obligation.	
555960	RT Spinning	Net Real Time Spinning Amount & Real Time Spinning Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Spinning cleared to an asset owner's zonal obligation.	
555970	RT Supplemental	Net Real Time Supplemental Amount & Real Time Supplemental Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Supplemental cleared to an asset owner's zonal obligation.	
555980	RT Other	Other RT charges that settle at the EDE EDE Load node including: Reliability Unit Commitment (RUC) MWP, RUC MWP Distribution Amount, RT Over Collected Losses Distribution Amount, RT Regulation Non-performance, RT Regulation Non-performance Distribution, RT Contingency Reserve Deployment Failure, RT Contingency Reserve Deployment Failure Distribution Amount, RT Regulation Deployment Adjustment, RT Out of Merit, RT Joint Operating Agreement, RT Reserve Sharing Group (RSG), RT RSG Distribution Amount, RT Demand Response, RT Demand Response Distribution Amount, RT Revenue Neutrality Uplift Distribution, RT Miscellaneous, RT Pseudo-Tie Congestion Amount, RT Pseudo-Tie Losses Amount, RT unused Reg-up mileage make whole payment, RT unused Reg-down mileage make whole payment	See Below
555990	TCR Activity	All Transmission Congestion Rights charges including: TCR Funding Amount, TCR Daily Uplift Amount, TCR Monthly Payback Amount, TCR Annual Payback Amount, TCR Annual Closeout Amount, TCR Auction Transaction Amount	See Below
555995	ARR Activity	All ARR Charges including: Auction Revenue Rights Funding Amount, ARR Uplift Amount, ARR Monthly Payback Amount, ARR Annual Payback, ARR Annual Closeout Amount,	See Below
447810	SPP IM Revenue - AR	The Arkansas share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447820	SPP IM Revenue - KS	The Kansas share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447830	SPP IM Revenue - MO	The Missouri share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447840	SPP IM Revenue - OK	The Oklahoma share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447840	SPP IM Revenue	Any and all of the above charge types that net to a revenue per the appropriate netting procedure(s)	

Day Ahead Other Charges

Day Ahead Make Whole Payment	Any resource that is committed by SPP during the Day Ahead market is eligible to recover the eligible costs associated with the commitment period.
Day Ahead Make Whole Payment Distribution	Cost allocation of Make Whole Payments for resources committed in the Day Ahead market to cleared loads.
Day Ahead Over Collected Loss Distribution	Rebate of surplus collected as a result of the marginal pricing of losses.
Day Ahead Demand Reduction	Charge or credit required in order to remove the settlement impact of grossing up the host load by the amount of the Demand Response Reduction output.
Day Ahead Demand Reduction Distribution	Charge or credit for each asset owner in which a Demand Response Reduction was cleared in order to fund the credits paid for the Demand Response Reduction.
Day Ahead Virtual Transaction Fee	Fee for virtual bids and offers.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Daily Amount	Day-ahead credit or charge for the exclusion of transactions associated with GFA's from market settlement of congestion, losses, and hedging instruments.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Monthly Amount	Monthly credit or charge for the exclusion of transactions associated with GFA's from market settlement of congestion hedging instruments.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Yearly Amount	Yearly credit or charge for the exclusion of transactions associated with GFA's from market settlement of congestion hedging instruments.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Daily Distribution Amount	A GFA carve-out credit or charge determined by the Asset Owners load ratio share for GFA revenue inadequacy.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Monthly Distribution Amount	A monthly charge or credit to ensure SPP revenue neutrality relating to the reversal of credits of GFA carve-outs through monthly TCR and ARR Payback.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Yearly Distribution Amount	A monthly charge or credit to ensure SPP revenue neutrality relating to the reversal of credits of GFA carve-outs through yearly TCR payback, TCR Closeout, ARR Payback, ARR Closeout.

Real Time Other Charges

Reliability Unit Commitment Make Whole Payment	Revenue guarantee to resources committed economically in the Real Time to cover eligible costs.
Reliability Unit Commitment Make Whole Payment Distribution	Cost allocation of Make Whole Payment for resources committed in RUC to an asset owner's Real Time deviations.
Real Time Over Collected Loss Distribution	Rebate of surplus collected as a result of the marginal pricing of losses.
Real Time Regulation Deployment Adj Amount	Adjustment to resource revenue for the combined impact of Energy and Regulation deployment.
Real Time Regulation Non-Performance	Charge when a resource with cleared Real Time Regulation-up and or Regulation-down operates outside of the operating tolerance
Real Time Regulation Non-Performance Distribution	Cost allocation of penalties collected for Regulation Non-Performance
Real Time Contingency Deployment Failure	Penalty for failing to provide Contingency Reserve amount when deployed.
Real Time Contingency Deployment Failure Distribution	Cost allocation of penalties collected for Contingency Reserve failure.
Out of Merit	Adjustment to compensate resources for additional cost incurred as a result of being manually dispatched away from the optimal point.
Real Time Joint Operating Agreement	Settlement for price coordination of a co-managed reciprocal flowgatge.
Real Time Reserve Sharing Group Amount	Settlement for response to Contingency Reserve event.
Real Time Reserve Sharing Group Distribution Amount	Asset owners payment, based on real time load ratio share, for response to a contingency event, by an RSG entity.

Real Time Demand Reduction	Credit or charge relating to the difference between the actual demand response reduction output and what was cleared in the day-ahead market.
Real Time Demand Reduction Distribution	Credit or charge to asset owners for each hour in which a demand response resource was dispatched.
Real Time Revenue Neutrality Uplift	Credit of charge calculated at each settlement location for each asset owner for each hour in order for SPP to remain revenue neutral.
Unused Reg-Up Mileage Make Whole Payment	A credit for each asset owner that is charged for unused regulation-up mileage at a rate that is in excess of the asset owners regulation-up mileage offer to the extent the resources regulation-up service margin is not sufficient to offset the charge induced by the difference in the two rates.
Unused Reg-Down Mileage Make Whole Payment	A credit for each asset owner that is charged for unused regulation-down mileage at a rate that is in excess of the asset owners regulation-down mileage offer to the extent the resources regulation-down service margin is not sufficient to offset the charge induced by the difference in the two rates.
Real Time Misc	Charge or credits that cannot be handled through standard Settlement billing.
Real Time Pseudo-Tie Congestion Amount	Real time congestion amount for resource or load that is pseudo-tied out of SPP balancing authority.
Real Time Pseudo-Tie Losses Amount	Real time loss amount for resource or load that is pseudo-tied out of SPP balancing authority.

TCR Activity

Transmission Congestion Rights (TCR) Auction Transaction	Settlement of the purchase or sale of a TCR instrument at auction.
TCR Funding	Credit or charge calculated for each TCR instrument held by an asset owner incurred by load bid into the Day Ahead market.
TCR Daily Uplift	Allocation of the deficit between congestion collections and TCR funding in Day Ahead.
TCR Monthly Payback	Use of excess congestion in a month to payback uplift in that month.
TCR Annual Payback	Use of excess congestion in a year to payback remaining uplift in that year.
TCR Annual Closeout	Allocation of the net difference between Auction Revenue Rights value and the daily settlement of TCR Auctions

ARR Activity

Auction Revenue Right (ARR) Funding	Settlement of an ARR instrument by the TCR auction price.
ARR Daily Uplift	Allocation of the net difference between ARR value and the daily settlement of TCR auctions.
ARR Monthly Payback	Use of excess auction revenue in a month to payback uplift in that month.
ARR Annual Payback	Use of excess auction revenue in a year to payback uplift in that year.
ARR Annual Closeout	Allocation of the net difference between Auction Revenue Rights value and the daily settlement of TCR Auctions

The Empire District Electric Company
Load and Capability Forecast
Based on Budgeted Load Forecast 2016-2019

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BUDGET ON-SYSTEM ENERGY MWHS
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BUDGET HEAT RATES (BTU/KWH)
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Fuel Types For Each Supply Side Resource

	Primary Fuel	Secondary Fuel	Start Fuel	Additional Fuel
Asbury 1	Asbury PRB Coal (~91.5%)	Asbury Blend Coal (~8.5%)	Oil	Tire Derived Fuel
Asbury 2	Asbury PRB Coal (~91.5%)	Asbury Blend Coal (~8.5%)	-	Tire Derived Fuel
Iatan 1-2	Iatan Western Coal		Oil	
Plum Point	Plum Point Western Coal		Oil	
Riverton 10	Natural Gas		Natural Gas	
Riverton 11	Natural Gas		Natural Gas	
Riverton 12 CC	Natural Gas		Natural Gas	
Energy Center 1	Natural Gas		Natural Gas	Oil
Energy Center 2	Natural Gas		Natural Gas	Oil
Energy Center 3	Natural Gas		-	Oil
Energy Center 4	Natural Gas		-	Oil
State Line 1	Natural Gas		Natural Gas	Oil
SLCC 1x1	Natural Gas		Natural Gas	
SLCC 2x1	Natural Gas		Natural Gas	

Approximate % blends in the table are on an MMBtu basis (91.5%/8.5% for Asbury)
Corresponding approximate % blends on a weight (ton) basis are (93%/7% for Asbury)
PRB is an abbreviation for Powder River Basin
CTs with oil as an additional fuel can burn oil if natural gas is unavailable or if oil is more economical

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Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect any such costs to be material, although recoverable in rates.

Electric Segment

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO2), particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), and hazardous air pollutants including mercury. In the future they will include limits on greenhouse gases (GHG) such as carbon dioxide (CO2).

Compliance Plan

In order to comply with current and forthcoming environmental regulations, we are taking actions to implement our compliance plan and strategy (Compliance Plan). The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), which we discuss further below, are the drivers behind our Compliance Plan and its implementation schedule. The MATS require reductions in mercury, acid gases and other emissions considered hazardous air pollutants (HAPS). They became effective in April 2012 and require full compliance by April 16, 2015 (with flexibility for extensions for reliability reasons). The CSAPR was first proposed by the Environmental Protection Agency (EPA) in July 2010 as a replacement of CAIR and came into effect on January 1, 2015. We anticipate compliance costs associated with the MATS, CAIR and CSAPR regulations to be recoverable in our rates.

Our Compliance Plan largely follows the preferred plan presented in our Integrated Resource Plan (IRP), filed in mid-2013 with the MPSC. As described above under New Construction, the process of installing a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant has been completed. This addition required the retirement of Asbury Unit 2, a steam turbine rated at 14 megawatts that was used for peaking purposes. Asbury Unit 2 was retired on December 31, 2013.

In September 2012, we completed the transition of our Riverton Units 7 and 8 from operation on coal and natural gas to operation solely on natural gas. Riverton Unit 7 was permanently removed from service on June 30, 2014. Riverton Unit 8 and Riverton Unit 9, a small combustion turbine that requires steam from Unit 8 for start-up, are planned to be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled to be completed in mid-2016.

See "New Construction" above for project costs for both of these projects.

Air Emissions

The CAA regulates the amount of NOx and SO2 an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx and SO2 limits. Through the end of 2014, NOx emissions were regulated by the CAIR and National Ambient Air Quality Standard (NAAQS) rules for ozone (discussed below). Beginning January 1, 2015, NOx emissions are regulated by CSAPR and NAAQS rules for ozone. Through the end of 2014, SO2 emissions were regulated by the Title IV Acid Rain Program and the CAIR. Beginning January 1, 2015, SO2 emissions are regulated by the Title IV Acid Rain Program and the CSAPR.

CAIR:

The CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NOx but not for SO2. At this time we believe we are in compliance with CAIR, which was in its final year in 2014.

CSAPR:

The CSAPR requires 23 states to reduce annual SO2 and NOx emissions to help downwind areas attain NAAQS for fine particulate matter. Twenty-five states are required to reduce ozone season NOx emissions to help downwind states attain NAAQS for ozone. The CSAPR NOx annual program impacts our Missouri and Kansas units while the CSAPR NOx ozone season program impacts our units in these two states plus our unit in Arkansas.

The CSAPR divides the states required to reduce SO2 into two groups. Both groups must reduce their SO2 emissions in Phase 1. Group 1 states, which include our sources in Missouri and Arkansas, must make additional SO2 reductions for Phase 2 in order to eliminate their significant contribution to air quality problems in downwind areas. Empire's units in Kansas are in Group 2 of the CSAPR SO2 program.

Under the CSAPR Program, in our most current five-year business plan (2015 – 2019), which assumes normal operations while maintaining compliance with permit conditions, we anticipate that it may be economically beneficial to purchase allowances for some of these pollutants if needed, but at the time of this writing the allowance markets have not been fully developed. We are in position to comply with CSAPR in 2015.

Mercury Air Toxics Standard (MATS):

As described above, the MATS standard became effective in April 2012, and requires compliance by April 2015 (with flexibility for extensions for reliability reasons). For all existing and new coal-fired electric utility steam generating units (EGUs), the MATS standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply. On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under the MATS. The new standards affect only new coal and oil-fired power plants that will be built in the future. The update does not change the final emission limits or other requirements for existing power plants. We are in position to comply with MATS in 2015.

National Ambient Air Quality Standards (NAAQS):

Under the CAA, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including particulate matter (PM), NOx, CO, SO2, and ozone which result from fossil fuel combustion. Our facilities are currently in compliance with all applicable NAAQS.

In January 2013, the EPA finalized the revised PM 2.5 primary annual standard at 12 ug/m3 (micrograms per cubic meter of air). States are required to meet the primary standard in 2020. The standard should have no impact on our existing generating fleet because the regional ambient monitor results are below the PM 2.5 required level. However, the PM 2.5 standards could impact future major modifications/construction projects that require additional permits.

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. Based on the current standard, our service territory is designated as attainment, meaning that it is in compliance with the standard. A revised ozone NAAQS was proposed by the EPA on November 25, 2014 and the final rule is expected in October 2015. We believe this revised Ozone NAAQS would affect our region but it's too early to determine what, if any, impact it would have on our generating plants at this time.

Greenhouse Gases (GHGs):

As the EPA began to prepare for future regulations, GHG emissions have been reported for several years under the Mandatory GHG Reporting Rule. EDE and EDG's GHG emissions for each year, since 2013, have been reported to the EPA as required.

A series of actions and decisions including the Tailoring Rule, which regulates carbon dioxide and other GHG emissions from certain stationary sources, have further set the foundation for the regulation of GHGs. However, because of the uncertainties regarding the final outcome of the GHG regulations (discussed below), the ultimate cost of compliance cannot be determined at this time. In any case, we expect the cost of complying with any such regulations to be recoverable in our rates.

In April 2012, the EPA proposed a Carbon Pollution Standard for new power plants to limit the amount of carbon emitted by EGUs. This standard was rescinded, and a re-proposal of standards of performance for affected fossil fuel-fired EGUs was published in January 2014. The proposed rule applies only to new EGUs and sets separate standards for natural gas-fired combustion turbines and for fossil fuel-fired utility boilers. The proposal would not apply to existing units, including modifications such as those required to meet other air pollution standards which are currently being undertaken at our Asbury facility and at the Riverton facility with the conversion of simple cycle Unit 12 to combined cycle. The final rule is expected in the summer of 2015.

On June 2, 2014, the EPA released the proposed rule for limiting carbon emissions from existing power plants. The "Clean Power Plan" requires a 30% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil-fuel fired power plants across the nation, including those in Empire's fleet, to meet state-specific goals to lower carbon levels. The EPA has identified four building block strategies to achieve the best system of emission reduction (BSER). Included in these strategies are the following: efficiency improvements at fossil fuel power plants; using lower-emitting sources (such as natural gas combined cycle units); using more renewables and keeping nuclear sources; and using power more efficiently. States will use the building blocks to craft their compliance plans or may work with other states in developing a regional approach to compliance, in which case additional time is given for implementation.

The EPA is scheduled to issue the final rule for existing power plants by summer of 2015. Each state must submit its initial compliance plan by the summer of 2016 with additional time available by request until the summer of 2017 for a single state or the summer of 2018 for a multi-state approach. The EPA received greater than 2 million public comments by the December 1, 2014 closure of the comment period. State, federal and industry representatives voiced their concerns with the regulation as written and the potential impact on electric grid reliability and the cost to implement. State and industry representatives including Empire continue to evaluate potential paths forward if the rule is finalized as proposed by the EPA.

Also, on June 2, 2014, the EPA released the proposed carbon pollution standards for modified and reconstructed stationary EGUs. The proposed rule focuses on electric utility steam generating units and natural gas-fired stationary combustion turbines. The comment period ended October 16, 2014 and the EPA anticipates issuing a final rule in June 2015.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received all necessary discharge permits.

The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. In 2007, the United States Court of Appeals remanded key sections of these CWA regulations to the EPA. The EPA suspended the regulations. Following a series of court approved delays, the EPA published the final rule on August 15, 2014 with an effective date of October 14, 2014. Court challenges are expected. We expect the regulations to have a limited impact at Riverton given the planned retirement of unit 8 scheduled in 2016. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Our new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation, but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally affected by the final rule.

Surface Impoundments

We own and maintain a coal ash impoundment located at our Asbury Power Plant. Additionally, we own a 12% interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. As a result of the transition from coal to natural gas fuel for Riverton Units 7 and 8, the former Riverton ash impoundment has been capped and closed. Final closure as an industrial (coal combustion waste) landfill was approved on June 30, 2014 by the Kansas Department of Health and Environment (KDHE).

On April 19, 2013, the EPA signed a notice of proposed rulemaking to revise its wastewater effluent limitation guidelines and standards under the CWA for coal-fired power plants. The proposal calls for updates to operating permits beginning in July 2017. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs that might result from any new standards. All of our coal ash impoundments are compliant with existing state and federal regulations.

In June 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Federal Resource Conservation and Recovery Act (RCRA). In the proposal, the EPA presented two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. On December 19, 2014 the EPA finalized the requirements under the subtitle D solid waste provisions. We expect compliance to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at our Asbury Power Plant. This preliminary estimate was developed before the rule was finalized and will be updated to conform to the final rule. We expect resulting costs to be recoverable in our rates.

We have received preliminary permit approval in Missouri for a new utility waste landfill adjacent to the Asbury plant. Our Detailed Site Investigation (DSI) has been completed and was submitted to MDNR for review and approval in on January 21, 2015. Receipt of the final construction permit for the waste landfill is expected in early 2016.

Renewable Energy

On November 4, 2008 Missouri voters approved the Clean Energy Initiative (Proposition C) which currently requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014, increasing to at least 15% by 2021. We are currently in compliance with this regulatory requirement as a result of generation from our Ozark Beach Hydroelectric Project and purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas, and Elk River Windfarm, LLC, located in Butler County, Kansas. Proposition C also requires that 2% of the energy from renewable energy sources must be solar; however, we believed that we were exempted by statute from the solar requirement. On January 20, 2013 the Earth Island Institute, d/b/a Renew Missouri, and others challenged our solar exemption by filing a complaint with the MPSC. The MPSC dismissed the complaint and Renew Missouri filed a notice of appeal seeking review by the Missouri Supreme Court. On February 10, 2015 the Missouri Supreme Court issued an opinion holding that the legislature had the authority to adopt the statute providing the exemption but reversed the MPSC's holding that the two laws could be harmonized. The statute providing the exemption (which was enacted in August 2008) was impliedly repealed by the adoption of Proposition C because it conflicted with the latter law. We believe the matter will return to the MPSC for further action. While we are not in a position to accurately estimate the impact of this requirement, we expect any future costs to be recoverable in rates.

Kansas established a renewable portfolio standard (RPS), effective November 19, 2010. It requires 10% of our Kansas retail customer peak capacity requirements to be sourced from renewables in 2012, increasing to 15% by 2016, and to 20% by 2020. We are currently in compliance with this regulatory requirement as a result of purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas and Elk River Windfarm, LLC, located in Butler County, Kansas.

Projected Position for Allowances 2016-2019

SO2 Acid Rain	2016	2017	2018	2019
Allowances allocated	11,741	11,741	11,741	11,741
Estimated allowances needed for emissions	1,409	1,381	1,361	1,331
Allowances allocated less allowances needed for emissions	10,332	10,360	10,380	10,410

SO2 CSAPR Group 1

Allowances allocated	5,878	5,568	5,568	5,568
Estimated allowances needed for emissions	1,403	1,375	1,357	1,325
Allowances allocated less allowances needed for emissions	4,475	4,193	4,211	4,243

SO_2 CSAPR Group 2

Allowances allocated	1,079	1,079	1,079	1,079
Estimated allowances needed for emissions	6	6	6	6
Allowances allocated less allowances needed for emissions	1,073	1,073	1,073	1,073

NO_x Annual CSAPR

Allowances allocated	2,155	1,984	1,984	1,984
Estimated allowances needed for emissions	1,430	1,392	1,430	1,372
Allowances allocated less allowances needed for emissions	725	592	554	612

NO_x Ozone Season CSAPR

Allowances allocated	726	624	624	624
Estimated allowances needed for emissions	655	596	654	635
Allowances allocated less allowances needed for emissions	71	28	(30)	(11)

SO_2 acid rain: all units are included

SO_2 CSAPR group 1 includes all MO units

SO_2 CSAPR group 2 includes Riverton only

Plum Point is not included in this summary

Riverton combined cycle SO_2 and NO_x emissions are estimated based on annual emissions estimated in construction permit (100 % CF) and adjusted to 50% CF for 2016-2019.

SCHEDULE TWT-9
NP VERSION

****Denotes Highly Confidential****

Net F&PP Summary
MO Rate Case Run (ER-2016-0023)

	GWH	CF	F &PP Cost ($000) Incl Start	$/MWH		Starts	Hours	GBTU	Avg HR
Asbury 1	1,099.40	64.5%	24,150.10	21.97		24	5,900	11,581.70	10,535
Iatan 1	572.30	76.7%	9,669.10	16.90		12	6,996	5,758.60	10,062
Iatan 2	726.70	78.8%	11,231.00	15.45		12	7,272	6,700.40	9,220
Total Iatan	1,299.00	0.0%	20,900.10	16.09		24	14,268	12,459.00	9,591
Plum Point (100 MW)	612.20	69.7%	11,803.10	19.28		14	6,859	5,984.60	9,776
Plum Point PPA O&M			3,006.05						
Plum Point PPA Env			1.76						
Plum Point PPA UT			644.97						
Riverton 10	-	0.0%	-	-		0	-	-	-
Riverton 11	-	0.0%	-	-		0	-	-	-
Riverton 12 CC	889.00	53.9%	18,933.80	21.30		42	5,402	6,293.90	7,080
Total Riverton	889.00	35.8%	18,933.80	21.30		42	5,402	6,293.90	7,080
Energy Center 1	3.50	0.5%	144.30	41.23		3	49	48.70	13,914
Energy Center 2	3.10	0.4%	120.20	38.77		3	41	41.50	13,387
Energy Center 3	51.00	11.8%	1,659.00	32.53		157	1,110	547.00	10,725
Energy Center 4	50.90	11.8%	1,655.00	32.51		154	1,104	545.30	10,713
Total EC	108.50	4.7%	3,578.50	32.98		317	2,304	1,182.50	10,899
State Line 1	15.00	1.8%	611.50	40.77		10	172	201.70	13,447
State Line CC	916.00	35.1%	20,255.00	22.11		68	3,531	6,699.80	7,314
Total SL	931.00	27.1%	20,866.50	22.41		78	3,703	6,901.50	7,413
Gas Turbines	1,928.50		43,378.80	22.49		437	11,409	14,377.90	7,455
Total Thermal	4,939.10		103,884.87	21.03				20,136.50	4,077
Ozark Beach	54.00	38.4%							
Total EDE (less fixed)	4,993.10		103,884.87	20.81					
Elk River Wind	573.80	43.5%	** **	** **	17.0% PP & Wind % of NSI				
Meridian Way Wind	329.40	35.7%	** **	** **					
Total Model	5,896.30		134,505.87	22.81					
Purch Power Demand Charge			10,068.68						
Undist-Oth-Train			3,572.85						
Gas Fixed FT			5,962.45						
Gas Dmd Commodity Chg			255.93						
Gas Dmd Losses Chg			1,084.47		359.45 additional GBTUs for losses (2.50%)				
Gas Storage			279.00						
Total Gas DMD			7,581.85						
Hedge Cost			4,568.43						
Total Resource Cost	5,896.30		160,297.684	27.19					
Total Revenue	5,896.30		(152,488.280)	(25.86)					
Native Load Cost	5,311.10		147,253.298	27.73					
ARR/TCR/FTR			(3,494.681)						
Net FPP w DMD			151,568.021	28.54					

GBTU Gas	14,377.90
GBTU with losses	14,737.35
GCF Gas	13,959.13
Heat Cont Gas	1.03
Avg Gas Cost	3.25

Unidst-Oth-Train and Gas FT not allocated to generating units in this summary report

Slight inconsistencies may occur due to rounding

starts and hours are reported from the PROSYM model

NP

FAC Comparison

Description	Current FAC Base Total Company	Proposed FAC Base Total Company
FUEL		
Fuel	$ 94,834,279	$ 98,898,983
Gas Transportation - Variable	$ 147,028	$ 255,927
Gas losses (LUF) at Cost of Gas	$ 776,334	$ 1,084,470
AQCS Consumables (Ammonia, Limestone, PAC)-Variable	$ 1,523,679	$ 2,142,668
Staff Removed from FERC 501 (Admin/Labor)	$ (174,495)	$ -
Freeze Control Coal Adder	$ 28,895	$ -
Other Fuel Related (Undistributed & Other and Unit Train)	$ 3,734,040	$ 3,572,855
TOTAL FUEL AND RELATED COSTS	**$ 100,869,760**	**$ 105,954,902**
PURCHASED POWER ENERGY CHARGES		
Purchased power energy (e.g., Plum Point PPA and Wind PPAs)	$ 40,228,865	$ 36,522,550
50 MW Plum Point O&M Cost-Variable	$ 4,118,601	$ 3,652,771
Purchased power energy	$ 44,347,466	$ 40,175,321
SPP INTEGRATED MARKETPLACE		
Native Load Cost	-	$ 147,253,298
OTHER ENERGY COSTS		
Net Emission Allowances	$ -	$ -
RTO Transmission	$ 5,054,101	$ 5,861,084
Net ARR/TCR		$ (3,494,681)
LESS: Net Renewable Energy Credits (REC)	$ (1,162,426)	$ (495,617)
LESS: Off-System Sales Revenue	$ (6,805,841)	$ (152,488,280)
TOTAL FUEL AND PURCHASED POWER FOR EMPIRE FAC BASE	**$ 142,303,060**	**$ 142,766,027**
Total kWh's	5,302,880,000	5,311,097,835
Base Cost per kWh	**$ 0.02684**	**$ 0.02688**
Base Cost per MWh	**$ 26.84**	**$ 26.88**

The proposed FAC base factor was modeled with the SPP IM approach, which is a different methodology than was utilized to calculate the current FAC base factor