Amoren Cross Ex 2

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ILLINOIS

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March 20, 2012

Ms. Elizabeth Rolando, Chief Clerk
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL 62701

Re: **Ameren Illinois Company d/b/a Ameren Illinois**
Electric Service Schedule Ill. C.C. No. 1

Dear Ms. Rolando:

Attached for filing are the original and one copy of this letter and the following tariff sheets of Ameren Illinois Company d/b/a Ameren Illinois ("Company").

Electric Service Schedule Ill. C.C. No. 1

1st Revised Sheet No. 25.007 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.007)
1st Revised Sheet No. 25.008 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.008)
1st Revised Sheet No. 25.009 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.009)
2nd Revised Sheet No. 25.010 – Rider PER – Purchased Electricity Recovery
(Canceling 1st Revised Sheet No. 25.010)
1st Revised Sheet No. 25.011 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.011)
1st Revised Sheet No. 25.012 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.012)
1st Revised Sheet No. 25.013 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.013)
1st Revised Sheet No. 25.014 – Rider PER – Purchased Electricity Recovery
(Canceling Original Sheet No. 25.014)
Original Sheet No. 25.015
Original Sheet No. 25.016
Original Sheet No. 25.017

The purpose of this filing is detailed in Attachment A.

OFFICIAL FILE
ILL. C. C. DOCKET NO. 13-0476
Ameren Cross Exhibit No. 2
Witness Cheri Harden
Date 7-11-14 Reporter RE

jvoiles@ameren.com
217.535.5269

The Company is filing these tariff sheets on 45 day notice to be effective May 4, 2012.

Pursuant to 83 Illinois Administrative Code, Part 255, the Company has posted notice of this filing.

Please acknowledge receipt of the enclosed filing by providing Ameren Illinois with a file stamped copy of this transmittal letter.

If you have any questions, please call me at 217/535-5269.

Sincerely,

Jackie K. Voiles, Director
Regulatory Affairs

JKV/cic
Attachments
cc: Torsten Clausen – ICC w/attachments
Joy Nicdao-Cuyugan – ICC w/attachments
Kathy Stewart – ICC w/attachments

The purpose of this filing is to modify tariff language within Rider PER – Purchased Electricity Recovery to: 1) initiate a mechanism that gradually moves residential (BGS-1)[1] and small general service (BGS-2) power and energy "Retail Purchased Electricity Charges" toward their underlying cost basis, and 2) transition the Purchased Electricity Adjustment (PEA) factor from a component calculated separately by Rate Zone to one established for the Company. Both changes are positive for the continued development of a competitive electric power supply market by making price comparisons more uniform across Rate Zones in accordance with underlying costs, and gradually removing below cost discounts currently embedded within BGS prices.

BGS-1 and BGS-2 Pricing

Power is purchased by the Company through IPA contracts for all BGS customers without Rate Zone distinction. The cost of serving BGS is the same for all Rate Zones; however, Retail Purchased Electricity Charges are currently different among Rate Zones. BGS-1 and BGS-2 also contain non-summer declining block pricing, implemented to address bill impacts and not because of an underlying cost basis. Moreover, BGS-1 summer prices are lower than prices for the first 800 kWh of use in a non-summer period. Current procurement expenses indicate that summer costs are greater than non-summer costs. The proposed changes seek to move prices closer to cost, which in turn moves prices toward uniformity among Rate Zones.

The proposed BGS-1 and BGS-2 pricing changes follow the methodology agreed to in the Company's electric rate case that was withdrawn in early January 2012 (Docket No. 11-0282 (Cons.)). The ALJ's Proposed Order in that proceeding indicated that the movement of BGS-1 and BGS-2 prices toward cost under the proposed constrained approach was uncontested. The proposal herein modifies the uncontested proposal from the withdrawn rate case to address pricing that would have otherwise been developed in compliance tariffs filed at the conclusion of the electric rate case. The base BGS charges resulting from the withdrawn rate case would have established the starting point for further price adjustments. Instead, the proposed tariff language addresses BGS price changes from their existing level, those set in Docket Nos. 09-0306 – 09-0308 (Cons.) and subsequently adjusted per the Mitigation Adjustment section of the Rider.

Adjustments to BGS-1 and BGS-2 both begin with the current "Mitigation Adjustment" process of estimating the change to the per kWh average cost of the fixed price procurement portfolio as a result of an annual update from an IPA procurement event. For example, the average cost of the portfolio increased 2.03% after the 2011 IPA procurement event, and thus all BGS Retail Supply Charges were increased by 2.03%. The Company proposes the steps shown below concerning proposed revenue neutral changes to each class designed to move individual prices toward cost.

1. Restructure Retail Purchased Electricity Charges on a revenue neutral basis to each class to rebalance summer and non-summer prices,
2. Establish or retain, as applicable, the uniform Summer Retail Purchased Charge across Rate Zones for each respective class,
3. Establish or retain, as applicable, the uniform Non-Summer Retail Purchased Charge for the initial block across Rate Zones for each respective class,

[1] Rider PER is used to determine electric power and energy supply prices for Rider BGS – Basic Generation Service. Rider BGS is a fixed price service.

4. Gradually reduce any discounted prices relative to the initial block Retail Purchased Electricity Charge applicable to BGS-1 for usage over 800 kWh in a non-summer month, and
5. Gradually remove any discounted prices relative to the initial block Retail Purchased Electricity Charge applicable to BGS-2 usage over 2,000 kWh in a non-summer month.

The first step ensures summer and non-summer prices remain consistent with the relationship between summer and non-summer IPA procurement costs. For example, the IPA procurement costs from 2011 show summer costs are 5% greater than average annual costs, and non-summer costs are 3% below average annual costs. This step ensures that BGS-1 and BGS-2 each contain seasonal prices that generate revenue to recover seasonal forecast costs. Continuing with the example, BGS-1 non-summer prices would be set at 1.05 times the overall load weighted annual average price, and non-summer prices would be set at 0.97 times the overall load weighted annual average price. BGS-2 prices would be similarly established.

The second step establishes (and retains in future periods) uniform summer BGS prices across Rate Zones for BGS-1 and BGS-2, respectively. Similarly, the third step establishes (and retains in future periods) uniform initial block BGS charges across Rate Zones for BGS-1 and BGS-2, respectively. Present summer and non-summer initial block charges contain slight differences among Rate Zones, yet cost of service does not differ among Rate Zones.

The fourth step addresses discounted prices for BGS-1 non-summer usage over 800 kWh, with the intent to gradually increase the value so that it eventually equals the initial block price. Stated alternatively, this step begins moving non-summer BGS-1 prices toward a single, non-blocked, flat price structure. This step is further guided by examining bill impacts of 12 customer profiles. For situations where the price for non-summer use over 800 kWh is less than the price for the first 800 kWh, charges applicable to monthly non-summer use over 800 kWh are proposed to increase up to a level not to exceed the initial block charge, and also not to exceed an annual cost increase of more than 7.5% for any one of the twelve customer profiles in any of the Rate Zones. An annual cost increase is measured by comparing the total of DS-1 Charges, Electric Distribution Tax (EDT) Cost Recovery and BGS-1 Retail Purchased Electricity Charges in effect on the prior June 1 and those adjusted prices to be in effect on the subsequent June 1. The combination of both annual supply and delivery cost increase shall not exceed 7.5% for any one of the twelve customer profiles in any of the Rate Zones. Increased revenue generated from increasing non-summer tail block rates will be used to lower uniform non-summer prices.

The fifth step is unique to BGS-2, and addresses discounted prices for BGS-2 non-summer usage over 2,000 kWh in Rate Zones I and III, with the intent of increasing values over time to equal the initial block prices. Rate Zone II BGS-2 non-summer prices are already uniform (i.e., no price difference by usage block). The Rate Zone I BGS-2 non-summer price for use over 2,000 kWh reflects a 20% discount over the price for the first 2,000 kWh. For Rate Zone III, the differential is approximately 12%. BGS-2 serves small general use non-residential customers with peak demands up to 150 kW, and as such serves a much wider range of usages than BGS-1. Limiting increases by examining a range of profiles is not as practical as it is for BGS-1. Instead, the price change to non-summer BGS-2 use over 2,000 kWh is limited to 15%.

In the withdrawn rate case, the uncontested proposal was to eliminate non-summer BGS-2 pricing differences at the conclusion of the case. The proposed approach herein addresses potential rate impacts to customers by recognizing that changes to the overall procurement costs each June are unknown. If overall power supply costs decline in the upcoming IPA procurement event, it is possible that uniform non-summer pricing will be achieved. If overall power supply costs increase, it is likely that BGS-2 non-summer charges for use over 2,000 kWh in Rate Zone I, and perhaps Rate Zone III, will reach the 15% cap. For most affected customers the total bill impact results in a single digit percentage change. Moreover, BGS-2 contains far more small customers than it does large, thus as prices for use over 2,000 kWh increase, prices for the first 2,000 kWh will decrease. Most BGS-2 customers are likely to benefit from the rate redesign.

BGS-1 Hypothetical Example

A hypothetical example of the methodology for BGS-1 assuming an IPA procurement costs do not change in the upcoming procurement event is provided in the tables shown below. The hypothetical example is provided to help illustrate the methodology, and is not intended to be construed as a forecast of expected results.

Current BGS-1 "Retail Purchased Electricity Charges"

Prices	Rate Zone I Non-Heat	Rate Zone I Space Heat	Rate Zone I Metro-east	Rate Zone II All customers	Rate Zone III Non-Heat	Rate Zone III Space Heat
Summer - All kWh	$0.05045	$0.05045	$0.05045	$0.05019	$0.05011	$0.05011
Non-Summer, First 800	$0.06057	$0.06057	$0.06057	$0.06020	$0.05733	$0.05733
Non-Summer, +800 kWh	$0.06057	$0.03434	$0.02024	$0.03852	$0.05733	$0.01881

The table above shows BGS-1 base prices in effect as of June 1, 2011.

Mitigation Adjustment

Multiplier from Annual IPA Procurement Event Reflecting Change in Electric Supply Fixed Price Portfolio Costs

BGS Price Difference:	0.00%	*Hypothetical. For illustration only*
BGS Factor:	100.00%	

The Mitigation Adjustment table above shows the overall assumed cost change of serving fixed price customers following an IPA procurement event.

BGS-1 "Retail Purchased Electricity Charges" After Mitigation Adjustment

	Rate Zone I Non-Heat	Rate Zone I Space Heat	Rate Zone I Metro-east	Rate Zone II All customers	Rate Zone III Non-Heat	Rate Zone III Space Heat	
Prices							
Summer - All kWh	$0.05045	$0.05045	$0.05045	$0.05019	$0.05011	$0.05011	
Non-Summer, First 800	$0.06057	$0.06057	$0.06057	$0.06020	$0.05733	$0.05733	
Non-Summer, +800 kWh	$0.06057	$0.03434	$0.02024	$0.03852	$0.05733	$0.01881	
Class kWh							
Summer - All kWh	830,921,201	301,987,733	245,723,707	779,031,054	2,028,777,907	254,439,566	4,440,881,168
Non-Summer, First 800	905,161,431	374,104,154	263,407,512	901,181,928	2,194,797,009	366,350,851	5,005,002,885
Non-Summer, +800 kWh	235,195,726	474,858,116	154,594,335	404,477,747	742,089,851	302,021,892	2,313,237,668
Total	1,971,278,357	1,150,950,003	663,725,554	2,084,690,730	4,965,664,767	922,812,309	11,759,121,721
Revenue at Mitigation Adjusted Prices (Rate Redesign to be revenue neutral to these values, in aggregate)							
Summer - All kWh	$ 41,919,975	$ 15,235,261	$ 12,396,761	$ 39,099,569	$ 101,662,061	$ 12,749,967	$ 223,063,613
Non-Summer, First 800	$ 54,825,628	$ 22,659,489	$ 15,954,593	$ 54,251,152	$ 125,827,713	$ 21,002,894	$ 294,521,468
Non-Summer, +800 kWh	$ 14,245,805	$ 16,306,628	$ 3,128,969	$ 15,580,483	$ 42,544,011	$ 5,681,032	$ 97,486,948
Total	$ 110,991,408	$ 54,201,397	$ 31,480,343	$ 108,931,204	$ 270,033,765	$ 39,433,893	$ 615,072,029

Table above reflects BGS-1 charges after application of the uniform across-the-board mitigation adjustment (a factor of 100% indicates no change from the present BGS-1 charges). Under the hypothetical example, these are the prices that would be in effect for customers absent the proposed rate redesign changes. The table also shows BGS-1 sales in each respective price category by Rate Zone, and determines the annual revenue of such sales at the prices modified by the mitigation adjustment. Prices under the subsequent rate redesign need to recover approximately $615 million in order to be revenue neutral.

Rate Redesign (Revenue Neutral Changes to Class from Prices Adjusted by Mitigation Adjustment)

Seasonal Adjustment Determination

Procurement Costs from IPA Event	$/MWh	% of Annual Avg
Summer	$53.48	105.0%
Non-summer	$49.38	97.0%
Annual	$50.92	100.0%

	kWh	Revenue	Revenue/kWh
Annual Avg at Mitigated Price	11,759,121,721	$ 615,072,029	$ 0.05231
Summer Avg at Mitigated Price	4,440,881,168	$ 223,063,613	$ 0.05023
Annual Avg at Mitigated Price	7,318,240,553	$ 392,008,416	$ 0.05357

Target Seasonal Costs	Summer	Non-summer
Current Average Annual Cost	$ 0.05231	$ 0.05231
Seasonal Factor	105%	97%
Target Average Cost	$ 0.05492	$ 0.05074
Cost Diff from Mitigated Realization	$ 0.00469	$ (0.00283)
% Diff. from Mitigated Realized	9.34%	-5.3%

The table above shows the seasonal cost differences. For purposes of illustration, values from the 2011 IPA procurement event are used. The annual, summer, and non-summer averages at the mitigated price show 5.231 ¢/kWh, 5.023 ¢/kWh, and 5.357 ¢/kWh, respectively. The target average summer and non-summer costs are 5.492 ¢/kWh and 5.074 ¢/kWh, respectively. Summer prices are 0.469 ¢/kWh below the target cost and non-summer prices are 0.283 ¢/kWh above the target cost. The next table adjusts prices such that summer and non-summer prices recover respective seasonal costs.

Redesign BGS-1 Prices, Effective on Upcoming June 1

	Rate Zone I			Rate Zone II	Rate Zone III		
Prices	Non-Heat	Space Heat	Metro-east	All customers	Non-Heat	Space Heat	
Summer - All kWh	$0.05492	$0.05492	$0.05492	$0.05492	$0.05492	$0.05492	
Non-Summer, First 800	$0.05365	$0.05365	$0.05365	$0.05365	$0.05365	$0.05365	
Non-Summer, +800 kWh	$0.05365	$0.04177	$0.02661	$0.04610	$0.05365	$0.02523	
Revenue at Redesigned Prices							
Summer - All kWh	$ 45,634,192	$ 16,585,166	$ 13,495,146	$ 42,784,386	$ 111,420,463	$ 13,973,821	$ 243,893,194
Non-Summer, First 800	$ 48,561,911	$ 20,070,688	$ 14,131,813	$ 48,348,410	$ 117,750,860	$ 19,654,723	$ 268,518,405
Non-Summer, +800 kWh	$ 12,618,251	$ 19,834,824	$ 4,113,755	$ 18,646,424	$ 39,813,121	$ 7,620,012	$ 102,646,386
Total	$ 106,814,354	$ 56,490,678	$ 31,740,714	$ 109,779,220	$ 268,984,463	$ 41,248,556	$ 615,057,985
Difference from Revenue at Mitigated Prices (Redesign Revenue total to be equivalent to Mitigated Revene total for AIC)							
Summer - All kWh	$ 3,714,218	$ 1,349,885	$ 1,098,385	$ 3,684,817	$ 9,758,422	$ 1,223,854	$ 20,829,581
Non-Summer, First 800	$ (6,263,717)	$ (2,588,801)	$ (1,822,760)	$ (5,902,742)	$ (8,076,853)	$ (1,348,171)	$ (26,003,064)
Non-Summer, +800 kWh	$ (1,627,554)	$ 3,528,196	$ 984,766	$ 3,065,941	$ (2,730,891)	$ 1,938,981	$ 5,159,439
Total	$ (4,177,054)	$ 2,289,280	$ 260,371	$ 848,017	$ (1,049,322)	$ 1,814,664	$ (14,044)

In the table above, summer prices have been set uniformly among the Rate Zones, equal to the target summer seasonal cost of 5.492 ¢/kWh (see steps 1 and 2 described above). Non-summer prices for the first 800 kWh of use have been set at a uniform level across each of the Rate Zones (step 3 above). Likewise, non-summer prices for use over 800 kWh for non-heat customers in Rate Zone I and Rate Zone III remain equal to the initial block charge. For Rate Zone II, Rate Zone I Metro-east, and space heat customers in Rate Zone I and Rate Zone III, non-summer prices for use over 800 kWh have been increased subject to a 7.5% bill impact constraints shown in the table below (step 4 above). Aggregate non-summer prices recover 5.074 ¢/kWh, an amount equal to the target seasonal cost. In total, the redesigned prices recover revenue equal to that generated by existing prices adjusted for the "mitigation adjustment" (see the "Difference from Revenue..." table above).

Summary of Customer Profile Percentage Impacts

Percentage Difference (Prior and Proposed) - DS-1 and BGS1 Charges								
Usage Profile			Rate Zone I			Rate Zone II	Rate Zone III	
Summer	Oct & May	Nov-Apr	Non-Heat	Space Heat	Metro-east	All customers	Non-Heat	Space Heat
2,000	1,500	4,500	-5.8%	7.2%	7.1%	7.3%	-2.2%	7.1%
2,000	1,200	3,000	-4.6%	5.0%	4.7%	5.2%	-1.4%	5.2%
2,000	800	2,000	-3.2%	2.7%	2.4%	3.1%	-0.6%	3.5%
2,000	800	1,000	-1.2%	0.0%	-0.1%	0.4%	0.7%	1.5%
1,200	1,500	4,500	-6.9%	7.4%	7.3%	7.4%	-2.9%	7.3%
1,200	1,200	3,000	-5.9%	4.9%	4.5%	5.1%	-2.3%	5.2%
1,200	800	2,000	-4.6%	2.2%	1.8%	2.5%	-1.6%	3.2%
1,200	800	1,000	-2.7%	-1.2%	-1.4%	-0.9%	-0.4%	0.6%
800	1,500	4,500	-7.5%	7.5%	7.5%	7.5%	-3.4%	7.5%
800	1,200	3,000	-6.6%	4.8%	4.4%	5.0%	-2.8%	5.2%
800	800	2,000	-5.5%	1.9%	1.4%	2.2%	-2.2%	2.9%
800	800	1,000	-3.7%	-2.1%	-2.3%	-1.8%	-1.1%	0.0%

The customer profile percentage impacts shown above examine the usages billed at prior and proposed prices for BGS-1, DS-1, and applicable Electricity Distribution Tax (EDT) Cost Recovery. Adjustments to non-summer BGS-1 prices for use over 800 kWh continue until either 1) the value is equal to the initial block BGS-1 price, or 2) any one of the customer profiles exceeds an annual increase of 7.5%. The "prior" and "proposed" comparison examines prices in effect on the prior June 1 to those proposed to be in effect on the upcoming June 1. For example, for an adjustment effective June 1, 2012, "prior" rates are those in effect June 1, 2011 and proposed values are those expected to be in effect June 1, 2012. The customer profiles were developed in the electric rate case withdrawn in early January 2012 and represent a wide range of customer usage types.

BGS-2 Hypothetical Example

Similarly, a hypothetical example of the methodology for BGS-2 assuming IPA procurement costs do not change in the upcoming procurement event is provided in the tables shown below. The hypothetical example is provided to help illustrate the methodology, and is not intended to be construed as a forecast of expected results.

BGS-2 "Retail Purchased Electricity Charges" Effective on Prior June 1

	Rate Zone I	Rate Zone II	Rate Zone III
Prices	Secondary Delivery Voltage		
Summer - All kWh	$0.07281	$0.07021	$0.07208
Non-Summer, First 2000	$0.06600	$0.05687	$0.06275
Non-Summer, +2000 kWh	$0.05252	$0.05687	$0.05527

The table above shows BGS-2 base prices in effect as of June 1, 2011.

Mitigation Adjustment

Multiplier from Annual IPA Procurement Event Reflecting Change in Electric Supply Fixed Price Portfolio Costs

BGS Price Difference:	0.00%	*Hypothetical. For Illustration only*
BGS Factor:	100.00%	

The Mitigation Adjustment table above shows the overall assumed cost change of serving fixed price customers following an IPA procurement event.

BGS-2 "Retail Purchased Electricity Charges" After Mitigation Adjustment

	Rate Zone I	Rate Zone II	Rate Zone III	Total
Prices		Secondary Delivery Voltage		
Summer - All kWh	$0.07281	$0.07021	$0.07208	
Non-Summer, First 2000	$0.06600	$0.05687	$0.06275	
Non-Summer, +2000 kWh	$0.05252	$0.05687	$0.05527	
Class kWh				
Summer - All kWh	762,393,628	365,507,614	1,069,384,125	2,197,285,567
Non-Summer, First 2000	452,554,028	217,925,013	631,272,037	1,301,751,078
Non-Summer, +2000 kWh	820,813,305	429,337,859	1,144,450,077	2,394,601,241
Total	2,035,760,960	1,012,770,687	2,845,106,240	5,893,637,887
Revenue at Mitigation Adjusted Prices (Rate Redesign to be revenue neutral to these values, in aggregate)				
Summer - All kWh	$ 55,509,880	$ 25,662,304	$ 77,081,208	$ 158,253,391
Non-Summer, First 2000	$ 29,868,566	$ 12,393,396	$ 39,612,320	$ 81,874,282
Non-Summer, +2000 kWh	$ 43,109,115	$ 24,416,444	$ 63,253,756	$ 130,779,315
Total	$ 128,487,561	$ 62,472,143	$ 179,947,284	$ 370,906,988

Table above reflects BGS-2 charges after application of the uniform across-the-board mitigation adjustment (a factor of 100% indicates no change from the present BGS-2 charges). Under the hypothetical example, these are the prices that would be in effect for customers absent the proposed rate redesign changes. The table also shows BGS-2 sales in each respective price category by Rate Zone, and determines the annual revenue of such sales at the prices modified by the mitigation adjustment. Prices under the subsequent rate redesign need to recover approximately $371 million in order to be revenue neutral.

Rate Redesign (Revenue Neutral Changes to Class from Prices Adjusted by Mitigation Adjustment)

Seasonal Adjustment Determination

Procurement Costs from IPA Event	$/MWh	% of Annual Avg
Summer	$53.48	105.0%
Non-summer	$49.38	97.0%
Annual	$50.92	100.0%

	kWh	Revenue	Revenue/kWh
Annual Avg at Mitigated Price	5,893,637,887	$ 370,906,988	$ 0.06293
Summer Agv at Mitigated Price	2,197,285,567	$ 158,253,391	$ 0.07202
Non-summer Avg at Mitigated Price	3,696,352,320	$ 212,653,596	$ 0.05753

Target Seasonal Costs	Summer	Non-summer
Current Average Annual Cost	$ 0.0629335	$ 0.0629335
Seasonal Factor	105%	97%
Target Average Cost	$ 0.0660801	$ 0.0610455
Cost Diff from Mitigated Realizatio	$ (0.00594)	$ 0.00351
% Diff. from Mitigated Realized	-8.25%	6.1%

The table above shows the seasonal cost differences. For purposes of illustration, values from the 2011 IPA procurement event are used. The annual, summer, and non-summer averages at the mitigated price show 6.293 ¢/kWh, 7.202 ¢/kWh, and 5.753 ¢/kWh, respectively. The target average summer and non-summer costs are 6.608 ¢/kWh and 6.105 ¢/kWh, respectively. Summer prices are 0.594 ¢/kWh above the target cost and non-summer prices are 0.351 ¢/kWh below the target cost. The next table adjusts prices such that summer and non-summer prices recover respective seasonal costs.

Attachment A

Redesign Prices, Effective On Upcoming June 1

	Rate Zone I	Rate Zone II	Rate Zone III	Total	
		Secondary Delivery Voltage			
Prices					
Summer - All kWh	$ 0.06608	$ 0.06608	$ 0.06608		Uniform across RZ
Non-Summer, First 2000	$ 0.06125	$ 0.06125	$ 0.06125		Uniform across RZ
Non-Summer, +2000 kWh	$ 0.06039	$ 0.06125	$ 0.06125		Raise toward 1st Blk, subject to limit
Revenue					
Summer - All kWh	$ 50,378,971	$ 24,152,756	$ 70,664,903	$ 145,196,630	
Non-Summer, First 2000	$ 27,718,934	$ 13,347,907	$ 38,665,412	$ 79,732,254	
Non-Summer, +2000 kWh	$ 49,568,915	$ 26,296,944	$ 70,097,567	$ 145,963,427	
Total	$ 127,666,821	$ 63,797,607	$ 179,427,883	$ 370,892,310	
Difference from Revenue at Mitigated Prices (Redesign Revenue total needs to be equivalent to Mitigated Revenue total for AIC)					
Summer - All kWh	$ (5,130,909)	$ (1,509,547)	$ (6,416,305)	$ (13,056,761)	
Non-Summer, First 2000	$ (2,149,632)	$ 954,512	$ (946,908)	$ (2,142,028)	
Non-Summer, +2000 kWh	$ 6,459,801	$ 1,880,500	$ 6,843,811	$ 15,184,112	
Total	$ (820,740)	$ 1,325,464	$ (519,401)	$ (14,677)	
Percent Change in BGS-2 Charges: Proposed Redesign vs. Prior June 1					
Summer - All kWh	-9.24%	-5.88%	-8.32%		
Non-Summer, First 2000	-7.20%	7.70%	-2.39%		
Non-Summer, +2000 kWh	14.98%	7.70%	10.82%		

In the table above, summer prices have been set uniformly among the Rate Zones, equal to the target summer seasonal cost of 6.608 ¢/kWh (see steps 1 and 2 described above). Non-summer prices for the first 2,000 kWh of use have been set at a uniform level across each of the Rate Zones (step 3 above). Likewise, non-summer prices for use over 2,000 kWh for customers in Rate Zone II remain equal to the initial block charge. For Rate Zone III, non-summer prices for use over 2,000 kWh have been set equal to the initial block rate since the increase to the price was less than the 15% threshold. For Rate Zone I non-summer prices for use over 2,000 kWh have been increased subject to a 15% bill impact constraint. Aggregate non-summer prices recover 6.105 ¢/kWh, an amount equal to the target seasonal cost. In total, the redesigned prices recover revenue equal to that generated by existing prices adjusted for the "mitigation adjustment" (see the "Difference from Revenue..." table above).

Purchased Electricity Adjustment

Rider PER also contains a mechanism that ensures power supply revenue does not result in an over or under recovery of power supply costs. The Purchased Electricity Adjustment (PEA) mechanism provides credits or charges to customers to ensure costs and revenues are balanced. Presently, the PEA is computed for each Rate Zone. The proposed tariff change begins the process of combining the PEA beginning with costs after the May 2012 Determination Period.

Applying a single PEA factor is appropriate. Power and energy is procured by AIC without Rate Zone differentiation. The proposed BGS-1 and BGS-2 pricing methodologies will also eventually result in uniform prices across Rate Zones for each respective class. It makes sense that a PEA factor would also be uniform for all of AIC's customers. Also, the price changes proposed for BGS-1 and BGS-2 categories of service discussed above could initially result in differing levels of average revenue collected from each Rate Zone. Thus, absent a change, proposed changes to BGS-1 and BGS-2 pricing could result in greater differences in PEA's among Rate Zone. Movement toward a single PEA addresses this unintended consequence of moving away from non-summer blocked prices.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

NPE_g = Non-Summer On-Peak Energy, in MWh, equals the forecasted electric consumption of Customers taking service under this Rider for the wholesale peak periods consisting of the hours from 6AM until 10PM Central Prevailing Time (CPT) Monday through Friday except on days designated by the NERC, for the months of January, February, March, April, May, October, November, and December for Customer supply group, g

NOE = Non-Summer Off-Peak Energy, in MWh, equals the forecasted electric consumption of Customers taking service under this Rider for the wholesale off-peak periods consisting of all hours other than those included in the wholesale peak periods, for the months of January, February, March, April, May, October, November, and December for Customer supply group, g

NE_g = Non-Summer Energy, in MWh, equals the forecasted electric consumption of Customers taking service under this Rider for the months of January, February, March, April, May, October, November, and December for Customer supply group, g

Exp_g = Expansion Factor, in decimal format, equals one plus the average distribution loss factor (DLF), based on provisions in the Rates and Charges section of the Supplier's Terms and Conditions for Customer supply group, g

* Notwithstanding the previous provisions of this Retail Purchased Electricity Charges section, the $SRPEC_g$s and the $NRPEC_g$s are subject to a mitigation adjustment and rate redesign.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

* **Mitigation Adjustment and Rate Redesign**
Notwithstanding the above, the base Retail Supply Charges for each Rate Zone resulting from the ICC Order associated with Docket Nos.09-0306 – 09-0311 (Cons.) shall provide the initial baseline for changes in overall electric charges for any price classification. Prices shall be adjusted after each applicable IPA procurement event by an equal percentage amount per the Mitigation Adjustment subsection below. In addition, beginning with BGS-1 and BGS-2 charges effective June 1, 2012, the Company shall adhere to the following principles: 1) restructure Retail Purchased Electricity Charges on a revenue neutral basis to each class to rebalance summer and non-summer prices, 2) establish or retain, as applicable, the uniform Summer Retail Purchased Charge across Rate Zones for each respective class, 3) establish or retain, as applicable, the uniform Non-Summer Retail Purchased Charge for the initial block across Rate Zones for each respective class, 4) gradually reduce any discounted prices relative to the initial block Retail Purchased Electricity Charge applicable to BGS-1 for usage over 800 kWh in a non-summer month, and 5) gradually remove any discounted prices relative to the initial block Retail Purchased Electricity Charge applicable to BGS-2 usage over 2,000 kWh in a non-summer month. Adjustments to non-summer prices for use over 800 kWh for BGS-1 and 2,000 kWh for BGS-2 will occur after each annual IPA procurement event until all non-summer prices are uniform for each respective class. BGS-2 Retail Purchased Electricity Charges shall continue to be differentiated by Delivery Voltage. Charges adjusted by this section shall become the baseline charges for subsequent changes.

* **Mitigation Adjustment**
Purchased Electricity Charges for Customers served under BGS-1, BGS-2, BGS-3, or BGS-5 Service Classifications defined in Rider BGS will reflect a mitigation adjustment. The overall increase to all price classifications shall be equal to 100% of the average annual increase to Customers served under BGS-1, BGS-2, BGS-5 and BGS-3 Customers receiving bundled service. The bill increase limit percentages are determined by dividing the difference between proposed and present revenue by present revenue, as determined in the following equation:

RIDER PER – PURCHASED ELECTRICITY RECOVERY

$$C,t = (PB,t - CB,t) / CB,t$$

Where:

C,t = Percentage change for each Rider BGS price component.

PB = Proposed Purchased Electricity Charges are derived from the Retail Purchased Electricity Prices section of this tariff. The Purchased Electricity Charge ¢/kWh unit prices multiplied by kWh sales projected to be served in the applicable price category gives total proposed variable revenue, PB.

CB = Present Purchased Electricity Charges are equal to unit prices in effect at the time just prior to filing the informational sheet reflecting the updated Purchased Electricity Charges. The present Purchased Electricity Charge ¢/kWh unit prices multiplied by kWh sales projected to be served in the applicable price category gives total present variable revenue, CB.

* **Rate Redesign**

Beginning with BGS-1 and BGS-2 prices effective June 1, 2012, revenue neutral adjustments shall be made for each respective class. In the filing made within two (2) business days after the ICC approves the results of a procurement event, the Company shall further adjust Retail Purchased Electricity Charges as follows: i) the Summer Retail Purchased Electricity Charge shall be adjusted so the proportion between the Summer Retail Purchased Electricity Charge and average annual Retail Purchased Electricity Charge equals the proportion, to the nearest $1/100^{th}$, between the summer average Purchased Electricity Price (costs of procuring power and energy that are incurred pursuant to the Commission-approved procurement plan) and annual average Purchased Electricity Price; and ii) the Non-Summer Purchased Electricity Charges shall be adjusted by an average uniform amount necessary to adjust rates to ensure the combination of Summer and Non-Summer price changes are revenue neutral for the upcoming annual period.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

* Beginning with BGS-1 prices effective June 1, 2012 BGS-1 Non-Summer Retail Purchased Electricity Charges shall be redesigned to gradually eliminate declining block pricing, subject to the following guidelines: 1) establish or retain, as applicable, price uniformity among the non-summer initial block charges (those applicable to the first 800 kWh of monthly non-summer use) among Rate Zones and applicable BGS-1 pricing categories within Rate Zones, and any non-summer charges applicable to monthly use over 800 kWh that are equal to the initial block charges, and 2) increase charges applicable to monthly non-summer use over 800 kWh for those pricing categories that are below the initial block charge up to a level not to exceed the initial block charge, and also not to exceed an annual cost increase of more than 7.5% for any one of the twelve customer profiles in any of the Rate Zones as shown below. An annual cost increase, as used in this paragraph, shall be measured by comparing the total of DS-1 Charges, EDT Cost Recovery and BGS-1 Retail Purchased Electricity Charges in effect on the prior June 1 and those adjusted prices to be in effect on the subsequent June 1. The combination of both annual supply and delivery cost increase shall not exceed 7.5% for any one of the twelve customer profiles in any of the Rate Zones shown below. Increased revenue generated from increasing non-summer tail block rates in item 2) above will be used to lower uniform non-summer prices in item 1) above.

* BGS-1 pricing categories within Rate Zones are as follows: Rate Zone I Customers, Rate Zone I Metro East Customers (including those premises/Customers formerly served under tariffs applicable to portions of Henderson and Hancock counties), Rate Zone I Customers served at Premises that on January 1, 2007 received service under Rider 5 – Residential Electric Space Heating, Rate Zone II Customers, Rate Zone III Customers served at Premises that on January 1, 2007 received service under the Residential Electric Space Heating provision within Service Classification 2 (space-heat group) and all other Rate Zone III BGS-1 Customers (non-space heat group).

*Asterisk denotes change

RIDER PER – PURCHASED ELECTRICITY RECOVERY

* The twelve customer profiles are as follows:

Profile	Summer kWh/Month	Non-Summer kWh/Month
1	2,000 June - September	4,500 November - April, 1,500 October and May
2	2,000 June - September	3,000 November - April, 1,200 October and May
3	2,000 June - September	2,000 November - April, 800 October and May
4	2,000 June - September	1,000 November - April 800 October and May
5	1,200 June - September	4,500 November - April, 1,500 October and May
6	1,200 June - September	3,000 November - April, 1,200 October and May
7	1,200 June - September	2,000 November - April, 800 October and May
8	1,200 June - September	1,000 November - April, 800 October and May
9	800 June - September	4,500 November - April, 1,500 October and May
10	800 June - September	3,000 November - April, 1,200 October and May
11	800 June - September	2,000 November - April, 800 October and May
12	800 June - September	1,000 November - April, 800 October and May

* Beginning with BGS-2 prices effective June 1, 2012, provided the Mitigation Adjustment produces an annual cost increase of less than 10% as a result of an annual IPA procurement event, BGS-2 Non-Summer Retail Purchased Electricity Charges shall be redesigned to gradually eliminate declining block pricing. The redesigned charges shall: 1) establish or retain, as applicable, price uniformity among the non-summer initial block charges (those applicable to the first 2,0000 kWh of monthly non-summer use) among Rate Zones and applicable BGS-2 pricing categories within Rate Zones, and any non-summer charges applicable to monthly use over 2,000 kWh that are equal to the initial block charges, and 2) increase charges applicable to monthly non-summer use over 2,000 kWh for those pricing categories that are below the initial block charge up to a level not to exceed the initial block charge, and also not to exceed a supply cost increase of more than 15%. An annual cost increase, as used in this paragraph, shall be measured by comparing BGS-2 costs for Primary Delivery Voltage service before and after IPA procurement event changes. Increased revenue generated from increasing non-summer tail block rates in item 2) above will be used to lower uniform non-summer prices in item 1) above.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

PURCHASED ELECTRICITY ADJUSTMENT MECHANISM

* In accordance with Section 16-111.5 of the Act that states the application of the retail purchased electricity charges must not result in over or under recovery of the Company's costs to procure electric power and energy for its Customers "due to changes in Customer usage and demand patterns," the Purchased Electricity Adjustment mechanism periodically equalizes the revenues from Customers taking service under Rider BGS, and Rider RTP as appropriate, for electric power and energy supply procured for them by the Company and the expenses incurred by the Company to procure such electric power and energy supply. The PEA, in ¢/kWh rounded to the thousandths of a cent, is determined and applied to each kWh provided by the Company under Rider BGS, and Rider RTP as appropriate, on a monthly basis. The PEA will be calculated by Rate Zone through the May 2012 Determination Period. Thereafter, the Accrued Expense (AE) and Accrued Revenue (AR) components of the PEA will no longer be separated by Rate Zones. Differences in the PEA applied to each Rate Zone for the amounts related to the Automatic Balancing (AB) and Adjustment (A) amounts on or before the May 2012 Determination Period may occur through the amortization period. The Company will amortize the AB amounts as of May 2012 over a period not to exceed 12months starting in the June 2012 Determination Period, and will calculate a rate that will be added to the non-Rate Zone differentiated PEA factor. Subsequent A amounts that relate to a Determination Period on or before May 2012 will be amortized over a period not to exceed 12 Effective Periods. The rate derived from the A amount will be added to the non-Rate Zone differentiated PEA factor.

The PEA factor is determined and applied in each Effective Period in accordance with the following equation:

$$PEA = \frac{[AE - AR + AB + A]_{amortized}}{U} \times \frac{100¢}{\$1}$$

Where:

PEA = Purchased Electricity Adjustment, in ¢/kWh rounded to the thousandths of a cent, applied as a credit or charge to kWhs provided to Customers taking service under Rider BGS, and Rider RTP as appropriate, during the Effective Period.

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* AE = Accrued Expenses, in dollars, equal to the sum of the accrued expenses incurred by the Company in accordance with this Rider for the electric power and energy procured for Customers taking service under Rider BGS, and Rider RTP as appropriate, during the Determination Period(s). AE will also be adjusted for an allocation of expenses for electric power and energy supply costs incurred under Rider HSS – Hourly Supply Service (Rider HSS) for the provision of electric power and energy obtained under Rider HSS for Rider RTP Customers. Starting with the October Determination Period and continuing through the May 2012 Determination Period, AE will be allocated to each Rate Zone based on the relative weight of kWh provided to Customers during the applicable Determination Period.

AR = Accrued Revenues, in dollars, equal to the accrued revenues recognized for Customers taking service under Rider BGS, and Rider RTP as appropriate, during the Determination Period(s) in accordance with this Rider.

AB = Automatic Balancing factor, in dollars, equal to the cumulative debit or credit balance resulting from the application of the PEA through the Determination Period(s). Such balance includes interest at the rate established by the ICC in accordance with 83 Ill. Adm. Code 280.70(e)(1).

A = Adjustment, in dollars, equal to an amount (a) ordered by the ICC or (b) determined by the Company, after discussion with the Staff, that is to be refunded to or collected from Customers to correct for accounting errors associated with the computation of previously applied PEAs. Such amount includes interest charged at the rate established by the ICC in accordance with 83 Ill. Adm. Code 280.70(e)(1). Such interest is calculated for the period of time beginning on the first day of the Effective Period during which such PEA was applied and extending through the day prior to the start of the Effective Period in which the A is applied. Such amount may be amortized over multiple Effective Periods with interest.

$[\ ]_{amortized}$ = Amortization of the quantity included in the brackets, as necessary, which in most cases will be a period not to exceed three (3) Effective Periods but could be for a period up 12 Effective Periods. For a situation in which amortization is not necessary, there is no amortization period.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

U = Usage, in kWh, forecasted to be provided to Customers taking service under Rider BGS, and Rider RTP where appropriate, during the Effective Period.

For the purposes of the computation of a PEA, a Determination Period means the calendar month for which the PEA is determined for Customers taking service under Rider BGS, and Rider RTP as appropriate, for which the Company procures electric power and energy. The first such Determination Period is June 2008.

For the purposes of the application of a PEA, an Effective Period means the monthly billing period during which a PEA is applied to kilowatt-hours (kWhs) provided to Customers taking service under Rider BGS, and Rider RTP as appropriate. The Effective Period is the first monthly billing period beginning no earlier than 15 calendar days after the 55 day MISO-conducted settlement process for electric supply for the Determination Period(s).

With a postmark dated no later than the 20th day of the month prior to the start of each Effective Period, the Company submits the PEA applicable during such Effective Period, along with supporting work papers, to the ICC for informational purposes. The Company is not required to obtain any consent or other approval, whether prospective, contemporaneous, or retrospective, from the ICC or any other entity in order to issue bills containing any such PEA or in order to collect any such PEA, provided, however, that any such PEA is subject to adjustment to correct accounting errors in accordance with Section 16-111.5(l) of the Act.

Any submission of a PEA postmarked after the 20th day of a month but prior to the start of the applicable Effective Period is acceptable only if such submission corrects an error or errors from a timely submitted PEA for such Effective Period. Any other such submission postmarked after such twentieth day is acceptable only if such submission is made in accordance with the special permission request provisions of Section 9-201(a) of the Act.

ADJUSTMENTS TO PURCHASED ELECTRICITY CHARGES

A Supply Cost Adjustment for each Rate Zone is applied to Customers billed under Rider PER for recovery of certain costs for procurement, working capital, and uncollectibles as defined below. The Supply Cost Adjustment factor will be reflected on the Company's monthly informational filing.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

Procurement Adjustment
This adjustment compensates the Company for all direct and indirect costs of procuring and administering electric power and energy supply for its Customers, other than amounts incurred under SFCs or amounts recovered under the Retail Purchased Electricity Charges, cash working capital adjustment, the uncollectible adjustment, and the CDU. These costs incurred by the Company will include, where applicable, professional fees, costs of engineering, supervision, insurance, payments for injury and damage awards, taxes, licenses, and any other administrative and general expense not already included in the auction prices or Retail Purchased Electricity Charges, as applicable, for power and energy service, not recovered elsewhere. The amount of this adjustment shall be established by the Commission in a Delivery Services rate case. The first adjustment shall be based upon the final Order for the Consolidated Docket Nos. 06-0070, 06-0071 and 06-0072 in the Companies Delivery Service rate cases. The adjustment shall be revised after each subsequent Delivery Services rate case.

Working Capital Adjustment
This adjustment compensates the Company for the amount of funds required to finance the day-to-day operations for Company-supplied power and energy. The working capital adjustment to the Purchased Electricity Charges will compensate the Company for the financing of the lag between the purchase of supply and the collection of those supply costs from Customers. The adjustment factor will be established by the Commission in the Company's electric Delivery Services rate cases. The first adjustment shall be based upon the final Order for the Consolidated Docket Nos. 06-0070, 06-0071 and 06-0072 in the Companies Delivery Service rate cases. The adjustment shall be revised after each subsequent Delivery Services rate case.

Uncollectibles Adjustment
This adjustment will be based upon the Company's uncollectibles experience for Company-supplied power and energy and shall be established by the Commission in a Delivery Services rate case. The first adjustment shall be based upon the final Order for the Consolidated Docket Nos. 06-0070, 06-0071 and 06-0072 in the Companies Delivery Service rate cases. The adjustment shall be revised after each subsequent Delivery Services rate case. The Uncollectibles adjustment only applies to Customers taking power and energy from the Company.

RIDER PER – PURCHASED ELECTRICITY RECOVERY

CONTINGENCY OBLIGATIONS

Pursuant to the provisions of Section 16-111.5(e)(5)(i), in the event of default by a supplier with which the Company entered into an IPA Contract in accordance with the provisions of the Procurement Obligations section of this Rider, the Company reviews such contract to determine (a) the amount of electric power and energy such supplier was contracted to supply, and (b) the number of days remaining in the term of the contract. In the event that a contract is terminated as a result of a default, such contract will be replaced as specified in Section 16.111.5(e)(5) and Section 16.111.5(n) of the Act.

Pursuant to the provisions of Section 16-111.5(e)(5)(iii), in any case in which there is insufficient electric power and energy supply procured under contracts awarded through the procurement process to fully meet the electric load requirement identified in the Procurement Plan, the Company will procure the necessary electric power and energy to make up for such insufficiency in MISO-Administered Markets. Notwithstanding the provisions of the previous sentence, if any component(s) of the electric power and energy that must be procured by the Company to make up for such insufficiency is not available in MISO-Administered Markets, the Company purchases any such component(s) in the wholesale electricity market.

MISCELLANEOUS GENERAL PROVISIONS

Each year beginning in 2009, the Company must conduct an internal audit of its costs and recoveries of such costs pursuant to this Rider. The internal audit shall include a determination whether 1) accounting controls are effectively preventing the double recovery of costs through Rider PER and through other means, 2) Rider PER is being properly applied to Customers bills, 3) revenues generated from Rider PER are recorded in appropriate accounts, and 4) costs recovered through Rider PER are reasonable. The Company must also prepare a report each year that summarizes the results of such audit. Such report must be submitted to the ICC in an informational filing, with copies of such report provided to the Manager of the Staff's Accounting Department and the Director of the Staff's Financial Analysis Division within 60 calendar days after the end of the effective period associated with the May Determination Period of such year. Such report must be verified by an officer of the Company.

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Each year beginning in 2009, no earlier than 90 calendar days after the end of the Effective Period associated with the May Determination Period of such year, a proceeding must commence in accordance with Section 16-111.5(l) of the Act to "provide for the correction, on at least an annual basis, of any accounting errors that may occur" in the application of the provisions of this Rider. Any correction of any such error is determined and applied in accordance with lawful orders issued by the ICC in such proceeding.

The provisions in this Rider are not subject to review under, or in any way limited by, Section 16-111(i) of the Act.

The Company must maintain confidentiality of all bidder and supplier information associated with any Procurement Plan to which it has access in a manner consistent with all applicable laws, rules, regulations, and tariffs.

The Company's Schedule of Rates, of which this Rider is a part, includes Customer Terms and Conditions and other tariffs. Service hereunder is subject to the Customer Terms and Conditions and such other tariffs, as applicable.