Kentucky Utilities Company's Response to the June 22, 2017 Order of the Kentucky Public Service Commission in Case No. 2016-00370

The Kentucky Public Service Commission's ("Commission") June 22, 2017 Order in Case No. 2016-00370 states:

> KU [Kentucky Utilities Company] should develop and implement a formal plan to address how KU will mitigate the loss of the approximately 325 MW municipal load, including, but not limited to, how KU will market the excess capacity and energy resulting from the municipals departing the system, the types of measures KU will implement to attract new or expanding load, and whether joining a regional transmission organization would be beneficial in its efforts to market the excess capacity and energy.[1]

KU respectfully submits this response to the Commission's Order.

Summary

Upon receiving in April 2014 five-year termination notices from the municipalities cited in the Commission's Order above, KU and Louisville Gas and Electric Company ("Companies") took action to mitigate the impact of the 325 MW of load that would depart in 2019. First, the Companies withdrew their then-pending application seeking approval to build Green River 5, a 670 MW generating unit. Second, the Companies secured 165 MW of short-term capacity through April 2019 to ensure adequate energy supply for their customers prior to the departure of the municipal load. Based on the Companies' then-current load projections, those actions were sufficient to address the municipal load departure without exceeding the optimal reserve margin range established in the Companies' most recent Integrated Resource Plan ("IRP"), which was their 2014 IRP. At that time the Companies' projected load growth indicated additional capacity resources would be needed by 2020.

Notably, not only the Companies' load projections, but also the national load projections of the U.S. Department of Energy, decreased significantly between 2014 and 2016. For the Companies, the decrease amounts to an almost 500 MW load-projection decrease for 2020 between the Companies' 2014 and 2016 load forecasts, both of which assumed the municipalities would have departed KU's system by that time. In other words, the current projected exceedances of the optimal reserve margin range established in the 2014 IRP result from overall lower-than-expected retail load growth, not the departure of the municipal load per se.

The Companies have six routine business and planning processes already underway that are addressing the relatively flat retail load projections: (1) completing a supply-side portfolio review; (2) proposing demand-side management ("DSM") program changes; (3) conducting a reserve margin study; (4) completing a regional transmission organization ("RTO") membership study; (5) continuing capacity and energy marketing efforts; and (6) continuing economic development efforts. The Companies believe these ongoing processes will ensure customers will continue to receive safe, reliable, and low-cost service.

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[1] Order at 27.

Background

The Companies have a well-established annual planning process that has enabled them to reliably meet their customers' around-the-clock energy needs both in the short term and long-term at the lowest reasonable cost. The Companies have used this process for decades, making updates and improvements over the years, to address changes in customer loads, environmental regulations, generation technologies, fuel markets, and market regulations. Since the early 1990s, the Companies have filed IRPs in accordance with Administrative Regulation 807 KAR 5:058, "Integrated Resource Planning by Electric Utilities" and have supplemented these IRPs annually with the submission of the Companies' resource assessments to the Commission in accordance with Administrative Case No. 387 (A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System).

An important part of the Companies' planning process is the long-term generation resource plan, i.e., the IRP, which includes load forecasting to evaluate the adequacy of resources available to meet projected load. The Commission Staff has historically found reasonable the Companies' load forecasting methodology. For example, in the 2014 IRP case (which is the Companies' most recent IRP case), Commission Staff stated in its 2016 Staff Report on the Companies' 2014 IRP, "Staff is generally satisfied with LG&E/KU's load forecasting approach, which is both thorough and well documented. The load forecasting model and its results are reasonable …."[2] Commission Staff further stated:

> Staff is generally satisfied with LG&E/KU's analysis of the many uncertainties it will be facing over the planning period. The improvements to its load forecasting processes are vital to improving the planning necessary to meet customers' load requirements and service expectations in the most cost-effective manner in both the short- and long-term planning horizon. The scope and depth of their reserve margin analysis, as well as the supply-side and demand-side screening analysis, were comprehensive and well developed.[3]

When the Companies filed their 2014 IRP on April 21, 2014, their load and resource projections were as shown in Table 1 below:

[2] *In the Matter of: 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, Commission Staff's Report at 17 (Mar. 1 , 2016).
[3] *Id*. at 59.

Table 1 – 2014 IRP Resource Summary (MW, Summer, No Municipal Departure)[4]

	2014	2015	2016	2017	2018	2020	2025	2028
Forecasted Peak Load	7,278	7,364	7,450	7,536	7,623	7,721	8,003	8,171
DSM	(306)	(336)	(365)	(394)	(423)	(406)	(406)	(406)
Net Peak Load	6,972	7,028	7,085	7,142	7,199	7,315	7,598	7,766
Existing Resources[5]	7,904	7,152	7,135	7,135	7,135	7,135	7,135	7,135
Planned/Proposed Resources[6]	0	640	649	649	1,319	1,319	1,319	1,319
Firm Purchases (OVEC)	155	155	155	155	155	155	155	155
Curtailable Load	128	131	131	131	131	131	131	131
Total Supply	8,187	8,078	8,069	8,070	8,740	8,740	8,740	8,740
Reserve Margin ("RM")	17.4%	14.9%	13.9%	13.0%	21.4%	19.5%	15.0%	12.5%
RM Shortfall (16% RM)	(99)	75	149	215	(389)	(255)	73	268

Prior to the 2014 IRP filing, although a number of KU's municipal customers had indicated the possibility that they might issue five-year termination notices, they had taken no definitive action in that regard. Therefore, as indicated in Table 1, the Companies had planned or proposed resources to meet anticipated load growth, which included municipal customers. Among the planned or proposed resources shown in Table 1, 640 MW result from the Cane Run 7 generating unit that was already approved and under construction at that time, as well as 9 MW for the proposed Brown Solar facility and 670 MW for the proposed Green River 5 generating unit. For the latter two units the Companies had filed an application with the Commission on January 17, 2014, seeking certificates of public convenience and necessity.[7]

On the same day the Companies filed their 2014 IRP, KU received notices of termination from nine municipalities that, as the Commission noted in its June 23, 2017 Order, have a combined

[4] 2014 Resource Assessment at page 5. Volume III of 2014 IRP.

[5] Existing resources include the retirement of Tyrone 3 in February 2013 and the planned retirement of Green River 3-4 in April 2015 and Cane Run 4-6 in May 2015.

[6] Planned/Proposed Resources include Cane Run 7 in May 2015, as well as Brown Solar in June 2016 and Green River 5 in January 2018.

[7] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Case No. 2014-00002.

load of approximately 325 MW. The Companies moved to address the changed circumstance by moving to hold the Green River 5 and Brown Solar proceeding in abeyance on April 30, 2014, and ultimately by withdrawing their application with respect to Green River 5 in August 2014. To ensure adequate energy supply while the municipal customers remained, the Companies sought and received Commission approval to enter into a power-purchase contract with Bluegrass Generation for 165 MW of capacity from May 2015 through April 2019.[8] Also, the Companies filed with the Commission an update to their 2014 IRP on October 17, 2014, to reflect the municipal load departure, Green River 5 withdrawal, and Bluegrass contract as shown in Table 2 below:

[8] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement*, Case No. 2014-00321.

Table 2 – 2014 IRP Addendum Resource Summary (MW, Summer, Includes Municipal Departure)[9]

	2015	2016	2017	2018	2019	2020	2025	2028
Forecasted Peak Load	7,364	7,450	7,520	7,607	7,337	7,394	7,666	7,826
DSM	(336)	(365)	(394)	(423)	(406)	(406)	(406)	(406)
Net Peak Load	7,028	7,085	7,126	7,183	6,932	6,988	7,260	7,421
Existing Resources[10]	7,152	7,135	7,135	7,135	7,135	7,135	7,135	7,135
Planned/Proposed Resources								
Cane Run 7	640	640	640	640	640	640	640	640
Brown Solar[11]	0	9	9	9	9	9	9	9
Bluegrass Capacity Purchase	165	165	165	165	0	0	0	0
Firm Purchases (OVEC)	155	155	155	155	155	155	155	155
Curtailable Load	131	131	131	131	131	131	131	131
Total Supply	8,243	8,234	8,235	8,235	8,070	8,070	8,070	8,070
Reserve Margin ("RM")	17.3%	16.2%	15.6%	14.6%	16.4%	15.5%	11.2%	8.7%
RM Shortfall (16% RM)	(90)	(16)	32	98	(29)	36	352	538

The Companies' updated 2014 IRP showed the Companies would begin to have a long-term capacity shortage relative to maintaining a 16% reserve margin beginning in 2020 even after fully accounting for the departure of the KU municipal customers in 2019. Those projections were entirely reasonable at the time, particularly given that the Companies had recently set or come close to several all-time peak load records: The Companies' summer peak demand of 7,175 MW occurred on August 4, 2010 as high temperatures across the service territory were approximately 100 degrees Fahrenheit. The Companies' winter peak demand of 7,114 MW occurred on January 6, 2014 during the polar vortex. The following year, on February 20, 2015, the Companies' peak demand was 7,079. In both cases, low temperatures were below zero degrees Fahrenheit.

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[9] 2014 IRP addendum resource summary at page 5.

[10] Existing resources include the retirement of Tyrone 3 in February 2013 and the planned retirement of Green River 3-4 in April 2015 and Cane Run 4-6 in May 2015.

[11] 90% of the capacity of Brown Solar is assumed to be available at the time of peak.

Therefore, the chief resource-planning difference between 2014 and today is not that some of KU's municipal customers will cease taking service from KU in 2019—as shown above, the Companies fully addressed that change by taking action in 2014—but rather that total retail load has been significantly lower than anticipated, as shown in Table 3 below:

Table 3 – Resource Summary from 2016 Rate Case (MW, Summer)

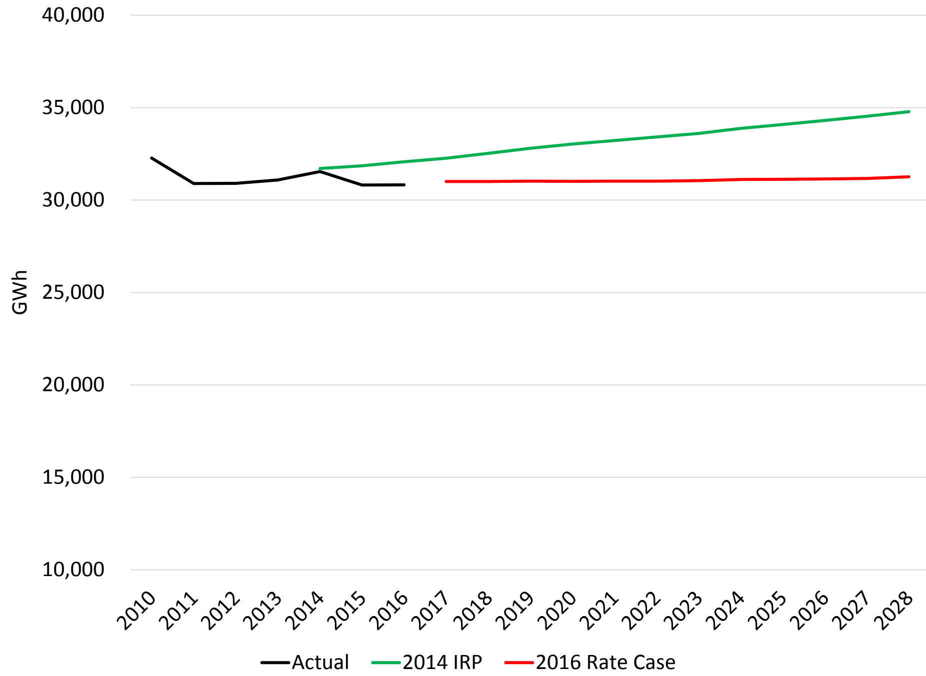
	2017	**2018**	**2019**	**2020**	**2025**	**2028**
Forecasted Peak Load	7,138	7,183	6,935	6,912	6,926	6,947
DSM	(331)	(378)	(383)	(364)	(364)	(364)
Net Peak Load	6,806	6,805	6,552	6,548	6,561	6,583
Existing Resources[12]	7,827	7,839	7,840	7,841	7,842	7,842
Bluegrass Capacity Purchase	165	165	0	0	0	0
Firm Purchases (OVEC)	152	152	152	152	152	152
Curtailable Load	130	130	130	130	130	130
Total Supply[13]	8,274	8,286	8,122	8,123	8,124	8,124
Reserve Margin ("RM")	21.6%	21.8%	24.0%	24.1%	23.8%	23.4%
RM Shortfall (16% RM)	(379)	(392)	(521)	(528)	(513)	(487)

Note that the revised 2014 IRP forecasted peak load for 2020 was 7,394 MW with a reserve margin of 15.5%. By 2016, the forecasted peak load for 2020 was 6,912 MW—almost 500 MW lower than the revised 2014 forecast—with a reserve margin of 24.1%. In addition to the decrease in forecasted retail peak load, forecasted retail electricity sales for 2020 has also decreased by approximately 2,000 GWh (see Figure 1)

[12] Existing resources include Cane Run 7 and Brown Solar.

[13] The change in total supply (approximately 50 MW) from the 2014 IRP is explained primarily by the following: Cane Run 7's summer capacity is 22 MW higher than the 2014 projection; the auxiliary loads for Mill Creek's environmental equipment is 17 MW lower than the 2014 projection; the summer rating of each Trimble County simple cycle combustion turbine was increased by 2 MW (12 MW total) over the 2014 projection to better reflect the units' capacity under summer operating conditions.

Figure 1 – LG&E and KU Retail Electricity Sales

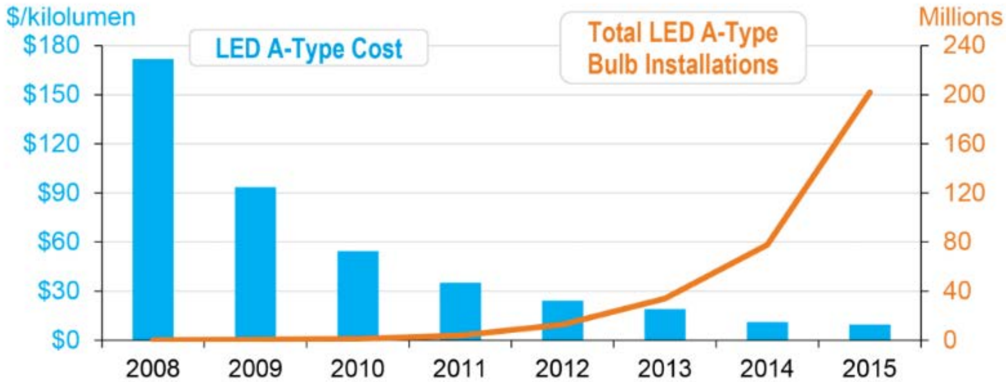


Several factors have contributed to the lower retail load forecast. For example, after decreasing more than 25 percent from 2010 to 2014, Kentucky's coal production declined an additional 45 percent from 2014 to 2016.[14] Other industries have also been impacted by economic declines. In November 2015, a large paper manufacturer in western Kentucky with a 50 MW annual peak and 360 GWh annual load shut down its operations.

Advancements in lighting technology have also contributed to slower load growth. According to the U.S. Department of Energy, the penetration of LED light bulbs increased by more than 2.5 times from 2014 to 2015, presumably due in part to marked decreases in the bulbs' cost in recent years (see Figure 2). This has had a significant impact on residential and commercial usage, 15 to 30 percent of which is for lighting.

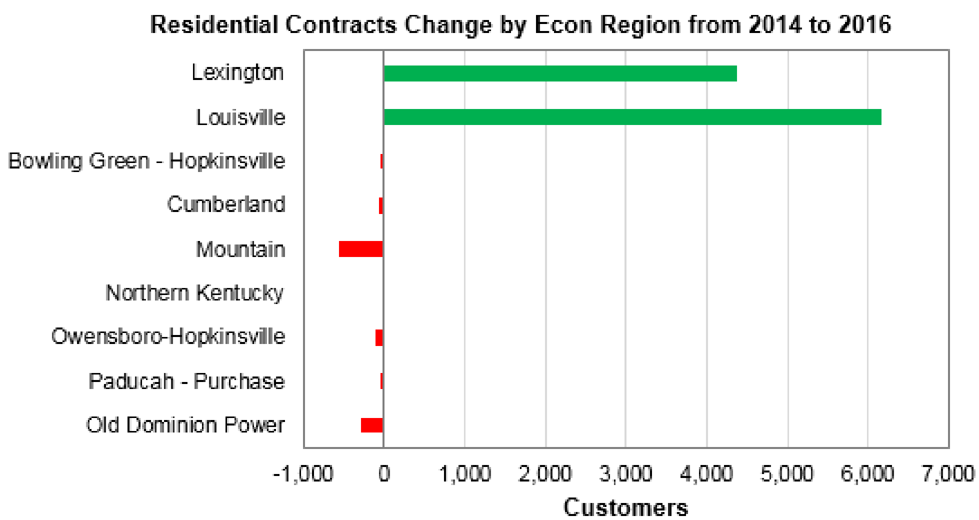
[14] http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q4-2016).pdf

Figure 2 – LED Lighting: Cost and Installation Trends
(Source: U.S. Department of Energy)



Also, the Companies have continued to see a shift in population from rural regions, where residential use-per-customer is typically higher, to urban regions, where residential use-per-customer is typically lower (see Figure 3).

Figure 3 – Rural to Urban Population Shift



These changing conditions and their effects on load projections are not unique to the Companies. For example, the U.S. Department of Energy's Annual Energy Outlook for 2014 forecasted total electricity sales of 4,454 TWh for 2025.[15] The 2016 Annual Energy Outlook revised that projection down significantly to 4,025 TWh for 2025.[16] In other words, the rapid changes in load characteristics that occurred just between 2014 and 2016 were significant and unforeseen by expert forecasters at all levels. That notwithstanding, the Companies continue to use their best efforts and the best available data to project load and ensure they can continue to provide safe,

[15] https://www.eia.gov/outlooks/archive/aeo14/pdf/0383(2014).pdf at Table CP4, AEO2014 reference case (accessed Sept. 13, 2017).
[16] https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf at Table CP4, AEO2016 No CPP (accessed Sept. 13, 2017).

reliable, and low-cost service.

Finally, the Companies have attempted to grow their lower-than-anticipated load and address the municipal departure by responding to several Requests for Proposals ("RFPs") for generating capacity and energy. In 2015, KU responded to RFPs for full requirements service from Kentucky Municipal Energy Agency and Berea Municipal Utilities. KU recently responded to an RFP from the city of Cairo, Illinois for full requirements service and is currently preparing a response to an RFP from Owensboro Municipal Utilities. Although the Companies have not been successful to date in their efforts to market long-term capacity and energy, they will continue to look for opportunities that will benefit existing customers. In addition, the Companies have personnel and resources dedicated to economic development and energy and capacity marketing efforts, all of which will continue and are described in greater detail in the following section.

Ongoing Planning Processes

Based on current load projections and the reserve margin range established in their 2014 IRP (i.e., 16% to 21%), and absent unit retirements, the Companies will not have a need for new generating capacity for at least 30 years,[17] and will have a reserve margin above the currently established optimal range for a number of years. The Companies have six routine business and planning processes already underway to address this situation:

Complete Supply-Side Portfolio Review. The Companies will submit a new IRP to the Commission in November 2018. The 2018 IRP will include a new reserve margin study and a complete review of the Companies' supply-side resources, including possible unit retirements (e.g., Brown Units 1 and 2 and Zorn) and an evaluation of the Companies' OVEC ownership. That analysis will also take into account possible environmental compliance savings associated with retiring certain units.

Propose DSM Program Changes. The Companies are currently reviewing their DSM programs as they prepare for their standard annual filing in November of this year and as the authority for the current portfolio will expire on December 31, 2018. The Companies expect that by February 28, 2018, the Companies will propose a portfolio of DSM programs for 2019 and beyond that is consistent with current load projections and the resulting value of DSM programs. The Companies may also propose revisions to their existing DSM programs prior to that date.

Conduct Reserve Margin Study. The Companies developed their current target reserve margin range (16% to 21%) in the context of adding new generation capacity in order to ensure reliability, comparing the cost of carrying new capacity to the new capacity's impact on reliability and generation production costs. The Companies will develop the target reserve margin range in the 2018 IRP in the context of retiring existing capacity, comparing the savings in fixed operating costs associated with retiring an existing unit to that unit's impact on reliability and generation production costs. Because the fixed operating costs for most of the Companies' generating units are considerably less than the cost of new capacity, the Companies' optimal target reserve margin range may increase. In addition, the optimal reserve margin target

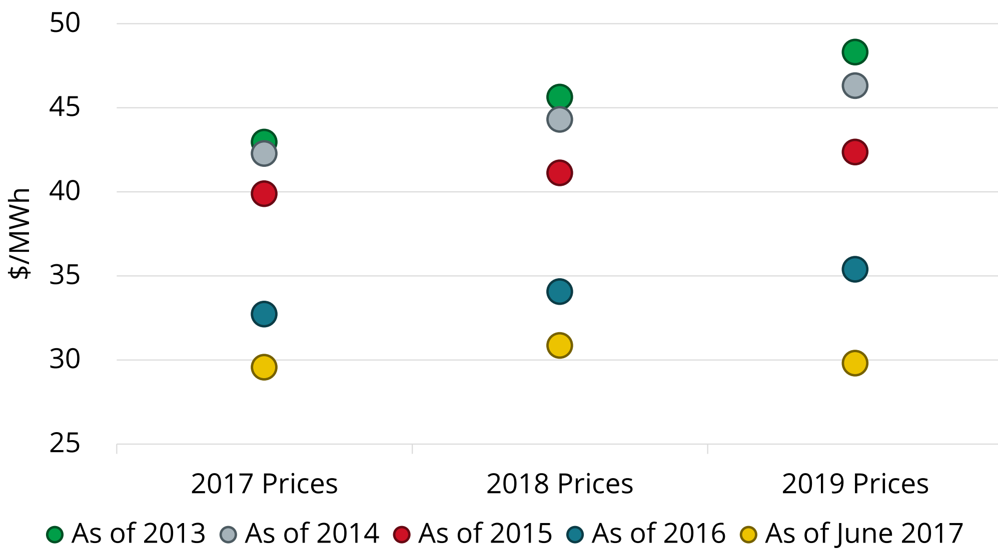
[17] See Sinclair rebuttal testimony at page 2.

is calculated as a function of forecasted peak demand under average peak weather conditions. The Companies' last reserve margin study was completed in 2013 for the 2014 IRP and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015). The Companies' next reserve margin study will be completed for the 2018 IRP and will consider the likelihood of these recently experienced winter peak demands along with the potential for retiring existing capacity.

Complete RTO Membership Study. The Companies will continue to evaluate the benefit to customers of being part of a Regional Transmission Organization (e.g., PJM and MISO). The Companies will provide the results of their currently ongoing analysis to the Commission no later than the end of calendar year 2018. That analysis will include consideration of congestion-cost risk, possible loss of fuel savings the Companies' customers currently receive through the joint economic dispatch of the Companies' generating units, and regulatory and other consequences of transferring functional control of the Companies' generating and transmission assets to an RTO, as well as possible RTO benefits.

Continue Capacity and Energy Marketing Efforts. The Companies will continue to seek out opportunities to maximize the value of their generating assets through the electricity markets. That includes marketing through the PJM and MISO energy and capacity markets; the Companies are market-participant members of both RTOs. The Companies try to make off-system sales or purchases in every hour of every day to reduce costs to customers. The ability to do this is a function of market electricity prices and available transmission capacity to ensure access to the market. Since 2013, forward electricity prices in the PJM have declined by 30% to 40%, resulting in fewer hours when market prices materially exceed the Companies' cost of producing electricity and placing downward pressure on off-system sales (see Figure 4).

Figure 4 – PJM West Electricity Hub Prices (Around the Clock)



MISO's pricing trends have been consistent with PJM. The potential for higher market prices continues to be hampered by low natural gas prices and lower than forecast regional loads. The Companies will continue to monitor the market and capture the opportunities for customers to lower costs through off system sales and purchases. The Companies will continue to respond to RFPs for generating capacity and energy whenever the opportunity would not jeopardize the Companies' ability to reliably serve their retail customers.

Continue Economic Development Efforts. The Companies will also continue their economic development efforts to grow load and improve the economy of the Commonwealth. More specifically, the Companies will continue to:

- Work in tandem with local, regional, and statewide officials to ensure adequate electric and natural gas facilities are available to support new developments;

- Provide leadership to the Kentucky Association for Economic Development;

- Work with the Kentucky Cabinet for Economic Development;

- Participate in the Industrial Asset Management Council Forums and the Utility Economic Development Association;

- Maintain and improve the Companies' economic development website and other communications; and

- Market directly to potential customers and customer groups seeking to locate or expand in the Companies' Kentucky service territories.