BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

REBUTTAL TESTIMONY OF

WILLIAM J. KEMP

ON BEHALF OF

GREAT PLAINS ENERGY INCORPORATED
AND
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE JOINT APPLICATION OF GREAT PLAINS ENERGY INCORPORATED, KANSAS CITY POWER & LIGHT COMPANY, AND WESTAR ENERGY, INC. FOR APPROVAL OF THE ACQUISITION OF WESTAR ENERGY, INC. BY GREAT PLAINS ENERGY INCORPORATED

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Q: Are you the same William J. Kemp who submitted Direct Testimony in this proceeding?

A: Yes, I am.

1. INTRODUCTION AND PURPOSE

Q: What did you do to prepare your Rebuttal Testimony?

A: I reviewed the testimony of all witnesses who addressed directly Great Plains Energy's ("GPE") estimates of efficiencies that would be produced from its acquisition of Westar Energy, Inc. ("Westar") (the "Transaction"). After considering logic and evidence presented by the relevant Staff and intervenor witnesses, I developed the rebuttal points that are set forth below.

For purposes of my rebuttal testimony, I focused on the major issues and aggregated my responses to similar points that were made by multiple Kansas Corporation Commission ("KCC" or "Commission") Staff ("Staff") and intervenor witnesses. Lack of rebuttal to specific points raised by a Staff or intervenor witness does not mean that I accept their positions.

Q: What is the purpose of your Rebuttal Testimony?

A: This testimony responds to Staff and intervenors and is intended to reinforce the basic message from my Direct Testimony, help focus on the most material issues in this case's voluminous record, and assist the Commissioners in making a well-informed decision in promoting the public interest.

More specifically, this testimony responds to certain ill-founded assertions contained in the testimony of Staff witnesses McClanahan, Glass, Diggs and Drabinski; Kansas City, Kansas Board of Public Utilities ("BPU") witnesses Lesser, Krajewski and Steffen; and Kansas Electric Power Cooperative, Inc. ("KEPCo") witness Kirsch. Each

of these witnesses takes issue with elements of my Direct Testimony. I will demonstrate through my Rebuttal Testimony that their positions are factually incorrect, suffer from serious logical flaws, or advocate bad public policy.

Finally, additional evidence will also be provided on key points.

2. EXECUTIVE SUMMARY

Q. Please summarize the conclusions of your Rebuttal Testimony.

A. My major conclusions are as follows:

- No witnesses have contradicted the fact the estimated total savings from the Transaction are generally consistent with the middle of the range of what has been achieved from similarly situated mergers. GPE's savings estimates are conservative and reasonable, and GPE is committed to achieve them.
- Staff and intervenor witnesses have taken overly adversarial positions that lie far outside of accepted industry practice or indeed established KCC precedents. They offer no plausible alternative paths to comparable customer benefits in comparable timeframes.
- The integration planning work since June 2016 has reinforced the reasonableness and achievability of the total estimated efficiencies from the Transaction. The initial savings estimates developed during the bid phase have been reviewed and validated by the integration planning teams, who have also found opportunities for additional efficiencies.
    - GPE's estimates of the savings from accelerated retirement of representative generation plants are reasonable and well documented.

- GPE's estimates of Supply Chain savings from the merger were not seriously challenged. GPE achieved Supply Chain savings in the 2008 KCP&L-Aquila transaction that were substantially higher than initially estimated, using an approach similar to that assumed in the GPE-Westar savings analysis.
- GPE's estimates of Shared Services savings from the merger are conservative and robust. To argue that Shared Services savings are not core benefits from the Transaction flies in the face of economic common sense, industry experience and regulatory precedent.
- GPE's estimated total savings in the Transmission and Distribution ("T&D") and Customer Service areas are not large, and should be very achievable. GPE is taking a very conservative approach to any such cost reductions, so that reliability and customer satisfaction are not negatively affected.

- GPE counted only operational and capital cost savings that were attributable to the Transaction, *i.e.*, they were directly created or enabled by the Transaction, and could not be realized in the normal course of business as separate companies. The Commission has accepted this standard in the past, notably in the KCP&L-Aquila transaction.

Q. Has the level of confidence by GPE's management and Board around the sufficiency of the overall savings changed since the time of the initial savings analyses by your team?

A. Yes. Their level of confidence has grown higher due to the more detailed integration planning work performed by GPE and Westar since June 2016. See the Rebuttal Testimony of Steven Busser for an overview of the status of the integration planning

work. The achievability of the initially estimated levels of total Transaction savings has been confirmed, and specific plans are being readied for execution.

Q. Before presenting your more detailed rebuttal points, do you have any general observations about the positions taken by Staff, BPU and KEPCo witnesses in their direct testimonies, especially regarding the Transaction savings estimates?

A. Yes. These witnesses include Staff witnesses Ann Diggs and Walter Drabinski, BPU witnesses Jonathan Lesser and Boris Steffen, and KEPCo witness Lawrence Kirsch. They start from the right foundation, *i.e.*, the KCC's Merger Standards and customer benefits. Will the proposed Transaction be good for Kansas and the customers of GPE and Westar? In attempting to answer this question, however, they largely veer off into narrow positions that lie far outside accepted industry practice and established KCC precedents. For example,

- They assert that a very narrow, "but for" test is necessary for counting customer benefits. While this might sound plausible, it's hypothetical nature would be very difficult to apply, and it can easily lead toward a defense of the status quo that denies very real benefits to customers.
- They would require the KCC to accept a large number of unproven hypotheticals about what GPE and Westar could or could not do to achieve savings without the Transaction.
- They advocate a very heavy-handed, intrusive regulatory approach, where the KCC would in effect direct major parts of GPE and Westar operations or second guess many critical private operational decisions. This goes against long-established, basic

goals of U.S. utility regulation, which are to emulate the outcomes of an efficient competitive market with private ownership and management of utility companies.

3. CORRECTIONS

Q. Do you have any corrections that you wish to make to your Direct Testimony?

A. Yes, I have one set of corrections that I would like to make. I do not believe these corrections are material.

I would like to revise the Costs to Achieve by non-fuel operations and maintenance ("NFOM") category for 2017 only, to make my Schedule WJK-3 consistent with the numbers for costs to achieve that were used in the final GPE financial model run for the bid. The total NFOM Costs to Achieve for 2017 increases by $1.2 million:

- Generation increases from $0.7 million to $1.4 million.
- T&D and Customer Service increases from $0.6 million to $1.2 million.
- Shared Services decreases from $5.5 million to $5.4 million.

There are no changes to Costs to Achieve for 2018-2020.

The revised summary table of estimated savings, incorporating these changes, is attached as Schedule WJK-3R.

4. SAVINGS ESTIMATION APPROACH

Q. A number of Staff and intervenor witnesses criticize GPE's approach to estimating Transaction savings during the bid process as not detailed enough and inadequately documented.[1] Do you agree with the characterization that the analysis was not detailed?

[1] See for example, Staff witness Diggs testimony at pages 23-25, BPU witness Lesser's testimony at pages 34-35, and BPU witness Steffen's testimony at pages 37-38.

A. No. GPE developed its initial savings estimates in the context of an auction process. The time and data available for the initial savings analysis were limited by the bid process timeline, as they often are in transactions such as this one. GPE's team had to operate within the same constraints as the other bidders. The process was not unusually abbreviated from my experience in other transactions. As is typical for many major decisions in the business world, GPE made its decisions around the bid using the best data available at the time.

After the bid process ended and the Hart-Scott-Rodino limitations on information sharing were lifted, information began to flow more freely between Westar and GPE. GPE and Westar have been developing since June 2016 successively more detailed integration plans, with quantified savings goals and executive accountability for achieving them. (See Mr. Busser's rebuttal testimony.) As corroboration of my experience, Mr. Flaherty also testifies that compressed timeframes for analysis for such M&A transactions are not unusual, nor do they mean that the analysis of the available data was not adequate to inform the business decision at hand.

Q. Was the savings estimation team in the bid process charged with developing definitive, exhaustive estimates of savings?

A. No. Our goal was not exhaustive quantification, but rather analysis adequate to answer the over-riding question: Are the reasonably achievable savings sufficient to meet the targets for making a competitive bid while maintaining GPE's financial and operational health and producing significant long-term benefits for customers and shareholders? We were conducting a sufficiency test.

GPE fully expected the savings mix to shift, and likely expand, as it drilled down into further detail in the integration planning process. And that indeed has been the case.

Q. Staff witness Diggs (at pages 14-17) and BPU witness Lesser (at pages 26-28) express concerns that the minimum savings targets communicated to the GPE savings estimation team ended up biasing the savings estimates. Do you agree?

A. No. As explained in the preceding Q&A, the team was not trying to come up with a definitive estimate. We were analyzing whether the reasonably achievable savings (singles and doubles, not home runs) were sufficient to make the deal work for the benefit of both customers and shareholders.

Ms. Diggs opines (with logical contradictions) that the minimum targets may have influenced the savings estimation team to be too aggressive – or too conservative. The guidance from GPE management to keep the estimates conservative, as well as the responsibility placed on GPE executives to achieve the savings, effectively prevented the team from pursuing overly aggressive savings estimates. The need to answer the sufficiency question in a parallel but opposing way encouraged the team not to get too conservative. The team had to find the right balance.

Assuring that the conservatively estimated savings are sufficient to generate benefits and preserve GPE's financial health is the same right balance for assessing whether the Transaction is in the public interest. Any savings beyond that are "icing on the cake," since GPE is proposing to pass all savings through to customers as they are flowed through the normal ratemaking process.

Mr. Lesser asserts at page 27 of this testimony that the savings estimates are flawed by "confirmation bias," because GPE started the process by giving the team an

initial set of merger-related savings. This assertion is erroneous because it ignores the actual sequence of events. As I state in my direct testimony at page 9, line 17 through page 10, line 10, Enovation provided the initial set of broad savings expectations to GPE in the analysis of utility industry experience with merger savings that was delivered to GPE in March 2016, before the start of the bid process and before Enovation was aware that GPE had opened discussions with Westar. Enovation had no role in defining the minimum target savings, and was not given any initial merger-related savings estimates, so the team could hardly be subject to confirmation bias.

Q. Mr. Lesser alleges at page 28, lines 1-7 that Enovation Partners "had a financial incentive to justify and exceed the initial merger-related savings estimates provided to him by GPE." Is this true?

A. No. This statement mischaracterizes my direct testimony. First, as discussed just above, GPE did not provide initial merger-related savings estimates to the savings estimation team. The targets discussed above were sufficiency minima, not estimates.

Second, Mr. Lesser misunderstands the phrase "fully utilized" as used in the referenced response to BPU Data Request No. 2-35[2]. "Fully utilized" does not mean getting paid more for specific results, as implied by Mr. Lesser. As commonly used in the consulting industry, and as intended in the reference data response, it means "devoting full time effort." A consultant is fully utilized on a project if he is working full time on it during the period. Enovation Partners' compensation from GPE was based on time input, not the level of estimated savings.

[2] See WJK-6

Q. Several Staff and intervenor witnesses (*e.g.*, McClanahan, Diggs, Drabinski, Lesser, and Steffen) interpret the phrase "savings that can be demonstrated from the merger" (from KCC Merger Standard (a)(ii)) as requiring a strict "but for" test, wherein only savings that could not be achieved in any way without the merger are allowed to be counted. Is this reading consistent with KCC precedents on merger approvals?

A. No. This was not the standard used during the proceeding which resulted in KCC approval of GPE's acquisition of Aquila, Inc. in 2008. I know this personally because I was a witness on the topic of transaction savings in that proceeding. The Commission used the same standard in that case as the one I applied in my Direct Testimony in this case. The testimony of Mr. James Proctor addresses more broadly the Commission's precedents on attributing benefits to mergers.

Q. Why is a strict "but for" standard impractical to implement?

A. As we can see from the Staff and intervenor testimonies filed in this case, it invites parties to deny the reality of benefits from the merger by creating unrealistic and unproven hypotheticals of how similar benefits could be achieved without the merger.

For example, BPU witness Steffen, at pages 24-34 of his testimony, suggests a number of ill-advised ideas on how GPE could help Westar achieve greater efficiencies without merging. These include GPE renting out part of its new customer information system ("CIS") to provide CIS services for Westar's customers (a recipe for information technology ("IT") and legal disaster), outsourcing back office and support services (more expensive and not as effective as merger consolidation), and selling its supply chain

advanced analytics capabilities to Westar (ignores violation of vendor contract confidentiality and required IT capabilities at Westar).

Reducing GPE's estimated savings on account of such hypothetical alternative paths to savings, as has been suggested by intervenors, would create an illusory standard that is not grounded in reality. It is not realistic to require that GPE and Westar should operate as though they have merged, when in fact they have not. If such a practice was practical and effective, we would see numerous of examples of such "pretend mergers." But we do not.

In effect, Staff and intervenor speculations would be substituted for the judgment of informed, experienced utility executive management on how best to achieve additional operational efficiencies. Such an artificial standard would discourage transactions that will clearly produce significant efficiency benefits for customers.

Q. How is a strict "but for" standard inconsistent with Staff and intervenor positions on tracking merger savings?

A. Staff and intervenor witnesses have already asserted that tracking of post-transaction cost changes that are specifically due to merger effects is pretty much an impossible task. That observation underlies much of the criticism by Ms. Diggs, Mr. Lester and Mr. Kirsch of my analysis of the utility industry experience with cost changes from mergers, as summarized in Schedule WJK-5 of my Direct Testimony. They state that many factors influence utility costs after a merger, and it is difficult to track those that are specifically merger-related. So their insistence now on a strict "but for" test for pre-transaction estimates of savings seems to be logically inconsistent. It implies that we can

predict with much more certainty than we can analyze ex post. That is not the way uncertainty typically resolves itself.

Q. What standard did you apply for counting savings as merger-related?

A. GPE counted only operational and capital cost savings that were attributable to the Transaction, *i.e.*, they were directly created or enabled by the Transaction, and could not be realized in the normal course of business as separate companies.

The phrase "in the normal course of business as separate companies" could count benefits as merger-related if they demonstrably can be achieved at significantly greater speed or lower risk through the merger, even if those benefits may hypothetically be possible to achieve as separate companies after normal business practices have been set aside.

For example, in the Supply Chain area, GPE's savings estimates include benefits from applying GPE's better practices in data analytics and contract management to Westar, and from extending the terms of the most favorable GPE or Westar contracts for similar services to the combined company. None of these benefits would be accessible in the near term without the merger.

Westar does not have the internal data bases or IT capabilities to implement advanced analytics in Supply Chain, and has not succeeded in recent years in its attempts to implement such analytics. GPE's better practices in data analytics and contract management cannot be "sold" to Westar.

Q. Has another definition of merger-related benefits been put forward that supports the reasonableness of the approach you have used in this regard?

A. Yes. BPU witness Boris Steffen on page 17 of his testimony cites as an external authority the Department of Justice's Horizontal Merger Guidelines. Although not applicable to this Transaction, these guidelines define merger-specific efficiencies as "only those efficiencies likely to be accomplished with the proposed merger and unlikely to be accomplished in the absence of either the proposed merger or another means having comparable anticompetitive effects."

This definition reflects the Department of Justice's ("DOJ's") considerable experience in evaluating potential mergers. (The phrase pertaining to comparable anticompetitive effects is not relevant to the proposed Transaction, having already passed DOJ review.) It still requires that the efficiencies must be likely to be accomplished with the merger, and unlikely without it. The unlikely, impractical hypothetical alternative paths to higher efficiencies no longer have equal standing to the merger path.

The net effect of the DOJ's definition of merger-specific efficiencies is very close to the definition used by GPE, and is consistent with the KCC's applied standard in the past. "From the merger" in this more pragmatic view would not mean "possible only with the merger," but rather something like "created by the merger or enabled (made much more likely or accelerated) by the merger."

Q. BPU witness Boris Steffen asserts that GPE overstates estimated savings from the merger in the way it includes capital cost reductions. Is he correct?

A. No. Mr. Steffen seriously mischaracterizes GPE's treatment of cost savings related to CapEx reductions. As can be seen plainly in Schedule WJK-3, GPE separates the savings

from O&M vs. CapEx reductions, to reflect how those types of cost reductions flow through revenue requirements, and ultimately produce rate benefits. The yearly savings estimated for CapEx reductions are not the current year CapEx reductions, as Mr. Steffen appears to assume, but rather the revenue requirement impacts of such CapEx reductions.

GPE did not, as he claims on page 56, lines 8-9 of his testimony, include $128.9 million in Generation CapEx savings improperly in non-fuel O&M ("NFOM") savings. First, the total estimated Generation CapEx savings for 2017-2020 is only $41 million, as shown on the CAPEX sheet of the GPE workpaper cited by Mr. Steffen (in footnote 128) which is the "annotated merger savings workbook[3]." Second, the $148 million in estimated Generation NFOM savings for 2017-2020 are all O&M cost reductions, as can be seen on the DATA and SUMMARY sheets (with pivot table drill-downs) of the annotated merger savings workbook. Mr. Steffen is mistaken.

Mr. Steffen's dismissal of the Supply Chain savings from avoided inventory carrying charges, as stated on page 57 of his testimony, similarly makes false conclusions based upon mistaken assumptions. GPE, like all utilities, applies an inventory carrying charge to inventory that it has purchased but has not yet used. The bulk of this carrying charge is for the very tangible costs of handling and warehousing associated with holding the inventory. A smaller portion of the carrying charge reflects the cost of capital tied up in inventory. Working capital is a rate base component with a revenue requirement impact. GPE's inventory carrying charge of 18.5% per year does not mean that GPE earns a capital return of 18.5% on inventory.

[3] The merger savings workbook served as the central repository for the great bulk of the data and analysis for calculating the estimated merger efficiencies. An annotated and partially live workbook, the "annotated merger savings workbook," was provided in GPE's response to Staff Data Request No. 135. See Schedule WJK-7.

The savings associated with avoided inventory carrying charges due to reductions in inventory levels from the merger are real, not "fictitious" as Mr. Steffen characterizes them. They have also been accepted by this Commission previously as part of merger-related savings, notably in the KCP&L-Aquila transaction.

5. GENERATION SAVINGS ESTIMATES

Q. BPU witness John Krajewski concludes on pages 9-11 of his testimony that it is not reasonable for the Parties (GPE and Westar) to retire the amount of capacity illustrated in the bid analysis, because the combined company would fall below the planning reserve margins required by the Southwest Power Pool ("SPP"). Do you agree?

A. No. GPE conducted a very detailed load and resource (L&R) analysis of the planning reserve margins that would result from the level of generation capacity retirements that were assumed in its savings estimates for the bid process. That analysis was provided as a workpaper in GPE's response to BPU Data Request No. 3-14.[4] It showed that the generation plant retirement scenario modeled by GPE for its savings estimates would meet the SPP planning reserve requirements at least through 2025. GPE fully expects that the generation retirement plan that emerges from the Integrated Resource Planning process that it intends to complete by July 2017 will also comply with the SPP's requirements.

Q. Please comment on the analysis Mr. Krajewski provided to support his conclusion.

A. Mr. Krajewski's analysis has several factual errors, particularly around Westar's loads and resources, that invalidate his conclusion.

[4] See Schedule WJK-8

- First, Mr. Krajewski fails to take into account the benefit of demand-side management ("DSM") resources for meeting peak load responsibility. Such DSM resources average 234 MW over the period 2017-2020. See line 9 on "L&R forecast" tab of the cited BPU Data Request No. 3-14 responsive workpaper.
- Second, Mr. Krajewski inaccurately represents capacity sales for the period. See line 31 on "L&R forecast" tab of the cited BPU Data Request No. 3-14 responsive workpaper.
- Third, Mr. Krajewski fails to take into account the retirement of Lawrence Energy Center Unit 3 ("LEC3"), Tecumseh Energy Center Unit 8 ("TEC8"), and Hutchinson Energy Center Steam Unit # 4 ("HUT4") as well as the 30% capacity accreditation of Westar wind plants in the Westar generation resources. See line 31 on "L&R forecast" tab of the cited BPU Data Request No. 3-14 responsive workpaper.
- Lastly, Mr. Krajewski understates Westar's capacity purchases by a factor of two. See line 25 on "L&R forecast" tab of the cited BPU Data Request No. 3-14 responsive workpaper.

Q. Did Mr. Krajewski make any errors in developing his analysis of KCP&L?

A. Yes. Mr. Krajewski mistook the response to BPU Data Request No. 3-14 to be reported surplus, not planning reserve requirement as clearly stated in response to BPU Data Request No. 3-14. In doing so, Mr. Krajewski underestimated KCP&L actual reserve capacity by approximately 50%.

Q. What is the net effect of these errors?

A. Mr. Krajewski's calculations misrepresent the available Westar and KCP&L capacity resources very substantially, and his conclusions on adequacy of reserves are therefore

wrong, as demonstrated clearly in the L&R forecast tab of the retirement analysis workpaper. His analysis on this very important issue should be rejected.

Q. BPU witness Jonathan Lesser states at page 55 of his testimony that the Westar and GPE estimate of merger-related savings from generation plant closures fails the "but for…" standard that he asserts should apply. Is this true?

A. No. First, as I discussed earlier in this testimony, the "but for" test, as applied by some Staff and intervenor witnesses, is not the appropriate standard for counting customer benefits from the merger.

Second, the avoided O&M and CapEx costs from retiring selected generation plants years in advance of the retirement dates that are in the separate companies' resource plans represent real savings from the merger.

Q. Did Mr. Lesser conduct a cost-benefit analysis of GPE's modeled generation retirement scenario?

A. No. Instead, Mr. Lesser provides a hypothetical analysis to support the cost side of the expected revenue change from the retired units. He then improperly attributes the decommissioning and dismantlement ("D&D") of the potential units as merger related costs while at the same time providing a worst case scenario on the cost of decommissioning and dismantlement of the retired facilities. Finally, Mr. Lesser cites an out of date Integrated Resource Plan ("IRP") developed in 2014 to estimate replacement power costs. I discuss why reliance in 2016 on a 2014 IRP is inappropriate later in my rebuttal testimony.

Q. Did Mr. Lesser provide an adequately comprehensive view of the revenue impacts of accelerating the retirement of the units?

A. No. Mr. Lesser provides a hypothetical analysis that assumes each operating plant is an individual asset and not part of a fleet of generating assets. He assumes that revenue "lost" from a retired unit is simply gone. This is grossly inaccurate.

Q. Why is this inaccurate?

A. The generation from the retired units will be picked up by the remaining operating units in the region. GPE and Westar own and operate many of those remaining units. The revenues generated from the units that continue to operate will thus be higher than they would have been if the retired units continued to operate. Mr. Lesser provides a one-sided impact of the change in revenue by considering only the lost revenue of the retired plants and not the net change in revenue from increased production of other units in the fleet.

Q. Why is it improper to attribute the D&D costs of the retired units to the merger?

A. Every unit in Westar's and KCP&L's fleet must at some point in time retire. When retirement occurs, the process of D&D must begin. Simply accelerating the date of retirement does not create this requirement; it exists independent of the merger and regardless of when the units are retired. Attributing the cost of D&D to the merger is not appropriate, because D&D costs will be incurred with or without the merger. Apart from possibly reflecting the time value of money from accelerating the start of the D&D process, the inclusion of D&D costs should be rejected entirely from inclusion in merger related costs to achieve.

Q. Even if the inclusion of the D&D costs is inappropriate, why is Mr. Lesser's depiction of the costs a worst case scenario?

A. Mr. Lesser makes two fundamental errors in his analysis. First, he assumes that there is no value to salvage of equipment and sale or reuse of the site. Second, he assumes that mothballing the units or deferring the decommissioning and dismantlement of the units is not a viable option, that the cost must be incurred immediately.

Q. Staff witness Walter Drabinski asserts on page 8 of his testimony that full implementation of merger-related changes will reduce generation O&M by 88%. Is this an accurate claim?

A. No. The percentage reduction in Generation Non-Fuel O&M ("NFOM") stated by Mr. Drabinski is overstated. Mr. Drabinski misreads GPE's testimony and workpapers. The Generation NFOM costs in the annotated merger savings workbook (Schedule WJK-8), which he cites as his source for these numbers, include only those GPE and Westar budget line items that will see cost reductions from the merger. They do not represent the total Generation NFOM budget.

The baseline "O&M Projection without Merger" shown for Generation in Exhibit WPD-2 understates very substantially the total budgeted O&M for the combined company. Exhibit WPD-2 shows total Generation NFOM in 2020 without the merger of about $90 million. That is a very small number for such a large generation fleet. In fact, the budgeted 2020 Generation NFOM for Westar alone is $288 million, as shown on line 19 of the "Sky O&M" sheet of the annotated merger savings workbook. GPE's Generation NFOM budget historically has been very close to that of Westar, so the total 2020 Generation NFOM budget for the two companies together would be approximately

$575 million, not $90 million, as claimed by Mr. Drabinski. A comparison of Exhibit WJK-4 shows that his posited $90 million baseline Generation NFOM budget was much too small. Exhibit WJK-4 shows that the actual Generation NFOM costs in 2015 for the two companies combined was $476 million, based on their Form 1 filings with the Federal Energy Regulatory Commission ("FERC").

Mr. Drabinski understates the baseline Generation NFOM costs by about 86 percent.as large as the combined GPE and Westar fleet. The percentages calculated in Exhibit WPD-2 are clearly in error, as are his assertions on page 8.

Q. Mr. Drabinski expresses bafflement at statements made by Terry Bassham related to the retention of jobs associated with the coal fleet of the GPE and Westar. Do you agree there are grounds for confusion in Mr. Bassham's statements?

A. No. Mr. Bassham is clear when he identifies maintaining "large baseload" coal plants post-Transaction. The units identified for potential closure are smaller, older, less efficient units that operate significantly less than the large baseload units. The largest units in the potential retirement list; LEC Unit 5 and Sibley Generating Station Unit 3 have capacities lower than 375 MW. The large units Mr. Bassham is referring to are 550 MW or larger.

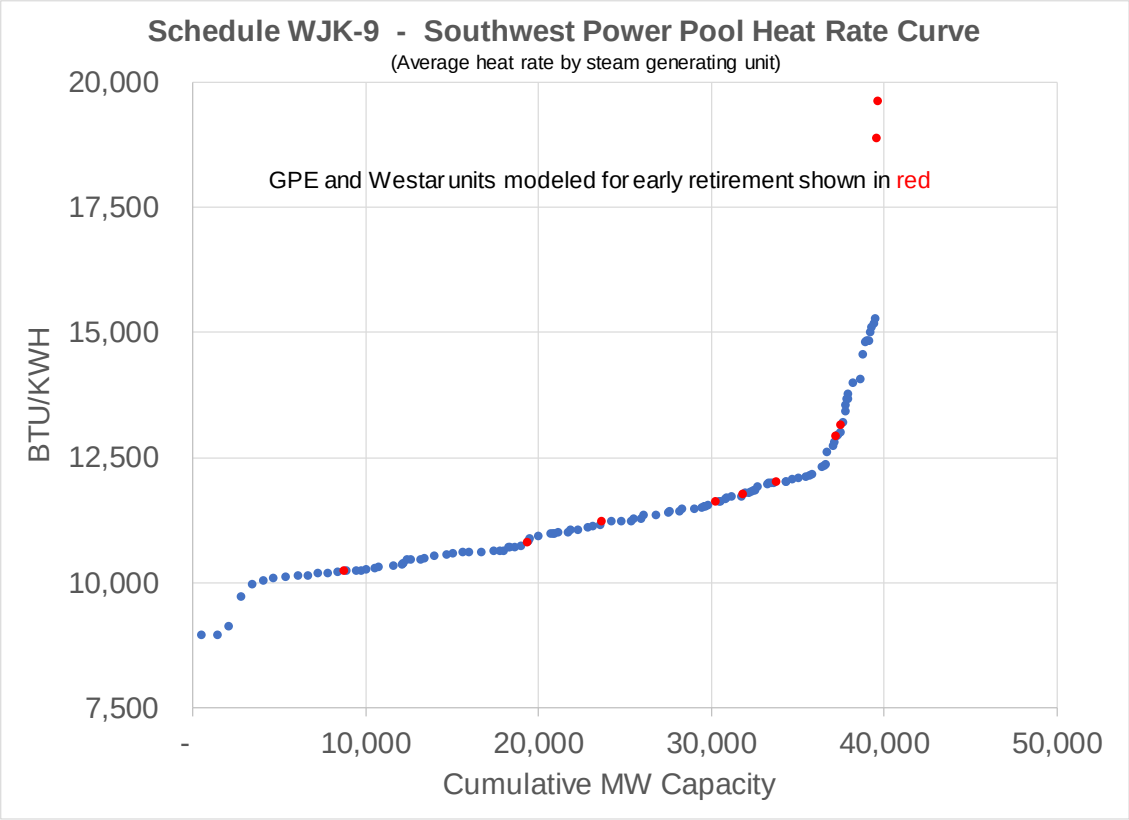
Q. Mr. Drabinski provides an analysis of the heat rates and efficiency of the combined fleet of generating units and concludes that there will be little improvement in the average heat rate of the fleet after the units identified for potential retirement are closed. Do you agree with this analysis?

A. No. Mr. Drabinski provides a list of heat rates for the combined fleet of generating units without providing a source for the heat rate values. Utilities are required to file detailed

operating characteristics and operating results of power plant units on an annual basis via Energy Information Administration ("EIA") Form 923. Heat rate by unit is an element of these reports. A review of the EIA Form 923 filings for KCP&L and Westar in 2015 highlights significant inaccuracies with the data provided by Mr. Drabinski. Consider Sibley Units 2 and 3. Sibley Unit 2 is a sub-critical 47 MW unit while Sibley Unit 3 is a super-critical 364 MW unit, yet Mr. Drabinski reports their heat rates as the same 10,402 Btu/kWh for both. The EIA Form 923 filings for 2015 show the heat rates for Sibley Units 2 and 3 to be 13,155 and 10,256 Btu/kWh respectively, a significant difference that is ignored by Mr. Drabinski.

Q. Do you agree with Mr. Drabinski's assertion that "heat rate was not a primary consideration in choosing retirements"?

A. No. Heat rate was one of several key or "primary" considerations. Consider the position of the units in question relative to the rest of steam generating plants in the SPP, shown in Schedule WJK-10 below. The schedule clearly shows that nine of the units are past the 50^{th} percentile of all steam units in SPP, with several of the units among the worst heat rates in SPP.



Q. Mr. Drabinski testifies that he found no consideration in GPE's generation savings estimates of the issue of residual book value at the date of plant retirement in the analysis of plants to shut down. Is this correct?

A. No. In fact, we did consider the impact of the accelerated retirement of units on residual book value. We assumed, conservatively, that a regulatory asset would be created and KCP&L and Westar would not suffer stranded asset losses since any plant closures would have been determined to be the best overall long-term solution for customers.

Q. Mr. Drabinski attributes the D&D costs of the retired units to the merger. Is this appropriate?

A. No. Like Mr. Lesser, Mr. Drabinski assumes that the merger creates the decommissioning and dismantlement costs. As shown the previous analysis of the D&D costs that Mr. Drabinski cites, which was performed long before the merger was contemplated, this is

obviously not the case. Unlike avoided O&M and CapEx costs due to the accelerated retirement dates, D&D costs will be incurred without or without the merger. Apart from possibly reflecting the time value of money from accelerating the start of the D&D process, the inclusion of D&D costs should be rejected entirely from inclusion in merger related costs to achieve.

Q. Mr. Drabinski estimates decommissioning and dismantlement costs of $71 million for Montrose and Sibley, at page 42 of his testimony. Is this an accurate estimate of the likely net costs?

A. No. Like Mr. Lessor, Mr. Drabinski makes two key errors in his analysis. First, he assumes that there is no value to salvage of equipment and sale or reuse of the site. Second, he assumes that mothballing the units or deferring the decommissioning and dismantlement of the units is not a viable option, that the cost must be incurred immediately. Dismantlement can be, and usually is, deferred.

Q. Does Mr. Drabinski make any other errors, in his estimate of $149 million for the decommissioning and dismantlement costs for Tecumseh Energy Center (TEC), Lawrence Energy Center (LEC), and Murry Gill, also on page 42 of his testimony?

A. Yes. First, he assumes that there are no economies of scale associated with decommissioning and dismantlement, so that larger units cost the same per MW as smaller units. Mr. Drabinski cites a weighted average cost for decommissioning and dismantlement of 97,394 per MW, this grossly overestimates the cost of decommissioning and dismantlement for larger units. An analysis of the individual unit decommissioning and dismantlement costs shows significant economies of scale.

Second, Mr. Drabinski assumes that the gas-fired steam units at Murry-Gill are equivalent in decommissioning and dismantlement costs per MW as a coal plant. This is not true; there is no coal handling equipment, no slag-contaminated metal, and most importantly no ash storage to remediate. These are also open air units, meaning there are no buildings or structures surrounding the plant equipment as one would find at the coal fired units.

Q. Mr. Drabinski offers an assessment of severance pay for the workforce at the retired units, on page 42 of this testimony. Is his estimate accurate?

A. No. Mr. Drabinski assumes all budgeted full time equivalent employees ("FTEs") at the retired units receive a severance. This is a faulty assumption regarding how GPE management will handle such a situation and wholly inconsistent with the GPE management team's prior actions in similar scenarios. In reality, KCP&L and Westar experience attrition throughout their workforces, including at more viable plants today, and GPE fully intends to maximize the relocation of any displaced staff due to any plant retirements. I discuss the reasonableness of GPE's assumption on average severance costs associated with FTE reductions later in this testimony.

Q. Mr. Drabinski offers a cumulative cost to achieve analysis for the accelerated plant retirements, on page 43 of his testimony. Do you agree with his conclusions?

A. No. While Mr. Drabinski offers the weak qualification "while some of these numbers use assumptions that one could question…," his analysis inappropriately includes D&D as costs to achieve as a result of the merger, and assumes that GPE will take no actions to reduce involuntary severance numbers or costs at retired plants. His estimates are not

reasonable. I stand by my estimates of the net savings from the modeled generation plant accelerated retirements.

6. SUPPLY CHAIN SAVINGS ESTIMATES

Q. Mr. Drabinski at pages 84-86 of his testimony and BPU witness Jonathan Lesser at pages 80-83 of his testimony assert that GPE and Westar could achieve the Supply Chain savings identified by GPE without the Transaction. Do you agree?

A. No. Messrs. Drabinski and Lesser both make faulty assumptions and omit important facts, and thus reach erroneous conclusion.

On page 85, lines 4 through 9, Mr. Drabinski states that he believes that the proposed merger between GPE and Westar is not necessary for achieving the following types of Supply Chain benefits:

- Utilizing more favorable contracts between the suppliers and contractors of each company;
- Leveraging economies of scale; and
- Reducing inventory and equipment across the combined company

There are several errors in his logic. Most fundamentally, the proposed merger between GPE and Westar will create an entity with almost double the procurement spending of either stand-alone company. This provides the combined company with negotiating leverage neither Westar nor GPE can use in negotiating better prices, best terms and conditions, or volume driven cost reductions.

Further, the combined company will have access to the existing supplier base of each stand-alone company, including the provisions currently in force for each of these contracts, such as pricing, line item price details, contract specific terms and conditions,

supplier service offerings and purchase item logistics and delivery alternatives. The combined company also will have much greater category specific procurement expertise, procurement history and experience within the purchasing organization than either stand-alone company.

Finally, neither stand-alone company has the scale and geographic breadth that the combined company will have to reduce reserve inventory and equipment levels as a percentage of overall volumes.

None of these important sets of capabilities or commercial advantage are available to the companies separately.

Q. How will the new Supply Chain capabilities and sources of commercial advantage create opportunities to achieve substantial Supply Chain savings?

1. The combined company can apply the best available terms of existing contracts held by the two companies, to quickly achieve procurement savings. These terms include prices, line item price elements, contract specific terms and conditions, supplier offered services and logistics options. By comparing each element of each contract, the combined company can select the optimal and least costly elements of similar contracts by procurement item or across a supplier's offerings, and use the results of this comparison to negotiate contract structure savings. The much larger purchasing volume of the combined company also gives GPE's procurement professionals the leverage to win acceptance of such extensions in favorable contract terms. As separate companies, GPE and Westar are restricted by the confidentiality provisions of their contracts with vendors from disclosing contractual terms to either each other

or to third parties, and would not have the increased volume needed to effectively negotiate better sets of terms and conditions.

2. Due to the doubling of its purchase volume, the combined company can leverage its doubled purchase volume to negotiate more favorable new contracts. This scale advantage drives reduced cost of purchasing for the combined company in several ways that can only be achieved as a result of the merger.
    - First, the combined company can offer existing or new suppliers significantly greater revenue opportunities, and in doing so, drive lower prices.
    - Second, the offer of obtaining or retaining much greater sales volume also allows Procurement to obtain new and more advantaged terms and conditions and increased supplier services that reduce the combined company's operating costs.
    - Third, increased scale economies can also enable the supplier to provide lower cost transportation and deployment alternatives for delivery of procured items to the company and/or its consumption locations.
    - Fourth, the combined company can also leverage its increased scale of purchases on a per item or per procurement category to order products in optimal order quantities and have purchases delivered via optimal transportation alternatives that lower procurement costs.
3. Reduced inventory and equipment reserves across the combined company is also a clear benefit from this proposed merger. Each stand-alone company must maintain reserve equipment and inventory to not only meet normal operating needs and reliability support, but also provide additional reserve inventory and equipment needed to respond to external adverse events including weather, major infrastructure

failures and catastrophic events. This reserve inventory and equipment is driven by the threats to system reliability and emergencies far more than overall inventory levels. Thus, while the combined company will have higher inventory and equipment levels in support of normal operations (approximately the sum of the stand-alone companies' levels), the reserve inventory and equipment can be reduced since reserve equipment and inventory can be shared across the combined company service territory. This allows the combined company to reduce its investments in both reserve inventory and equipment while maintaining or improving service levels and reliability, a savings that is only achievable as a result of the merger.

Q. Do you agree with Mr. Drabinski's assertion on page 85, lines 12-18 of his testimony, that GPE or Westar could join purchasing groups instead of merging, and achieve the same level of Supply Chain economies of scale?

A. No. He states, "If there are greater savings to be gained through a larger purchasing network, this could be achieved without a merger. Many small utilities, coops, and municipals have developed procurement consortia that achieve similar economies of scale." This is factually incorrect. While procurement consortia do exist that serve groups of smaller utilities, cooperatives and municipals, and these consortia can lower procurement costs modestly, their ability to achieve Supply Chain cost savings does not approach that of large utilities or even GPE or Westar prior to the merger.

Enovation Partners' professionals have worked with several of these smaller procurement consortia, and evaluated them for utility clients. We even helped establish and manage a procurement consortium that served a number of larger utilities. However,

the levels of savings produced by these groups are far lower than can be achieved from this proposed merger.

Several major impediments prevent procurement consortia form reaching anywhere close to the level of Supply Chain savings that mergers can provide:

1. Procurement consortia's effectiveness in achieving cost savings is severely limited by differences in the design requirements of each utility. Without moving to a common design standard with common procurement specifications, procurement consortia cannot effectively negotiate volume cost reductions of any significance.

   In the absence of strong central leadership by management and a compelling focus on resolving design differences, the utility industry has made very little progress toward common design requirements and procurement specifications. Utility mergers are generally the only large scale way to achieve common standards. GPE as a result of its prior merger with Aquila is one of the few utilities to achieve common standards and purchasing requirements across predecessor companies. That design harmonization is one of the biggest reasons that GPE exceeded its past Supply Chain merger savings goals in the Aquila transaction.

   Due to the prevalent design harmonization challenges, most utility procurement consortia focus either on specialty items (*e.g.*, nuclear parts and supplies), or commodity items (*e.g.*, office supplies, printing materials, janitorial services). They add very little value in the non-specialty, non-commodity items that make up the great bulk of utility purchases.

2. Suppliers offer pricing discounts based on the volume of purchases a company can make and the administrative costs required to serve a utility. Enovation Partners

is aware of only one isolated case where suppliers offered pricing discounts based on aggregate volume, and in that case the discounts applied only if ownership transfer was involved, *i.e.*, the purchasing consortium takes ownership of the purchases and acts as direct purchaser rather than agent. Otherwise, pricing is driven by size of the smallest size of utility involved, which severely limits the savings from joint procurement efforts.

As a result, utilities that do participate in procurement consortia are careful to align themselves with companies of similar size and do not allow membership by smaller utilities. GPE and Westar would not be allowed to join a procurement organization with much larger companies unless it was in a special utility procurement area like nuclear procurement. Even there, pricing discounts for larger companies are still greater.

More importantly, procurement consortia typically do not purchase and take ownership of purchased items because of tax costs, capital investment requirements and costs, and procurement group risks. They are too thinly capitalized to bear such costs and risks.

This lack of a capability by a procurement consortium to act as a true direct buyer means that the commercial terms are limited by the size of its smallest member. This key shortcoming in the business model has handicapped the performance of procurement consortia, greatly limited the procurement scope that it makes sense for them to undertake, and choked off their growth.

3. Procurement consortia have administrative and operating costs associated with both membership, procurement activities and overhead. These costs are above and

beyond the member utilities' own procurement process costs, and subtract from any negotiated cost savings. Again, procurement consortia cannot achieve the cost savings achievable through merger of sizable utility companies.

4. Procurement logistics and order administration is another area of cost savings where procurement consortia provide very little savings to their individual members. GPE and Westar as a merged company can achieve significant cost reduction in purchase administration, inbound logistics, internal purchase distribution and delivery, and inventory management. Separately, the stand-alone companies working with procurement consortia cannot achieve savings in these areas and their operations may even add a layer of cost beyond what a company incurs. This is why procurement consortia very rarely offer services in these important procurement areas.

In short, the proposed combined company can get much better pricing, operational and administrative cost reductions, and procurement operational savings than any procurement consortium available to the stand-alone companies.

Q. At page 85, beginning on line 16, Mr. Drabinski asserts that savings estimates related to reductions in capital expenditures, whether in the Supply Chain or other areas, are too speculative and subject to management and Board of Director discretionary judgment to be counted in merger-related savings. Do you agree?

A. No. This argument makes an artificial distinction between capital cost reductions and O&M cost reductions. Capital expenditures (in the form of assets in rate base) and O&M expenses both are included in the test year costs that are used to set revenue requirements and rates. Both types of cost reductions produce price benefits for customers.

It may be true that the timing of capital project execution and the related capital expenditures in the Generation, T&D and Customer Service functions is subject to slightly more management discretion than in O&M expenses. But the overriding drivers of both capital and O&M investments are operational needs, reliability requirements and growth demands. The ability to accelerate or delay capital project execution is quite limited and subject to regulatory oversight. The false assertion that capital expenditures are highly discretionary is not a reasonable basis for arbitrarily excluding capital expenditure ("CapEx") reductions from estimates of merger savings.

All projected CapEx savings from the proposed GPE and Westar merger are based on current operations standards and operating practices. GPE's CapEx program requirements ultimately are driven by reliability and service quality goals established under review and regulation by the Commission. They are neither speculative nor subject to broad management or Board of Directors discretion.

As for CapEx reductions in the Supply Chain area, Mr. Drabinski's argument carries even less weight and ignores the operating realities of the supply chain. The

capital expenditure reductions in the Supply Chain area are not driven by reductions in capital expenditure project volumes, but rather by capital expenditure avoidance from reductions in the costs of inputs into those capital projects, through the more favorable purchasing terms discussed above. Supply Chain CapEx savings are also produced by reductions in deployed capital for reserve inventory and equipment levels.

Q. At page 80, lines 12-19 of his testimony, Mr. Lesser challenges the last four of six drivers of Supply Chain cost savings referenced in your direct testimony and claims each of these cost savings drivers can be achieved without the merger. Do you agree?

A. No. His conclusions about these savings drivers are incorrect. I will address in turn the four challenged savings drivers.

1. The savings resulting from "optimizing contractor staffing levels" is achieved by aggregating the combined volume of work performed by each company independently, and managing it as a single integrated activity using resource optimization, strategic sourcing, skills alignment and resource scheduling. The combined volume from each stand-alone company enables resource efficiency savings and strategic sourcing savings. Without the merger, these savings cannot be achieved.

2-3. The savings resulting from "GPE's advanced analytics" and "procurement automation efficiency" predominantly drive labor and staffing efficiencies across Westar as well as reducing the costs of implementing new and advanced procurement technologies within Westar. While it may be possible for Westar by itself eventually to implement procurement automation and re-create the advanced analytics capabilities that GPE has developed over many years, Westar did not succeed in its first attempt to

implement procurement automation and has only indefinite plans to restart this initiative at some point in the future. Without a platform of procurement automation, which GPE possesses now and Westar does not, advanced analytics cannot be effectively applied to achieve the efficiencies of strategic sourcing or reduce procurement transaction costs.

Further, implementation of both procurement automation and advanced Supply Chain analytics takes most companies several years, is very costly and requires even longer to deliver measurable procurement savings. Without the merger, Westar will incur implementation costs significantly higher than GPE's costs to extend its existing capabilities across Westar, and at least several years of savings will be lost.

4. Finally, Mr. Lesser contends that the Supply Chain "best practices" can simply be sold by GPE to Westar, to deliver the purchasing cost savings identified in our merger supply chain analysis. This is not only wrong, it would be irresponsible. The customers and shareholders of GPE have paid for the time and expense of developing GPE's hard won expertise, and deserve to receive the benefits. GPE should not sell such expertise to Westar at any price less than the full value to Westar plus a return premium to recover the substantial costs associated with the distraction to GPE and the diversion of key GPE resources.

That is why no utility has established an organization to "sell" their Supply Chain best practices to other utilities. If Mr. Lesser's hypothetical were practical and attractive, we should see many examples of utilities doing so.

Further, Mr. Lesser's contention ignores the management reality that selling best practices does not result in the implementation of best practices, as many consulting firms have learned. Implementing best practices in Supply Chain or elsewhere requires hard

work, trial and error, effective learning, continual feedback and reinforcement over time, and generally requires automated systems for support. GPE's Supply Chain management team has demonstrated the knowledge, experience and procurement automation tools to effectively accelerate the implementation of best practices that Westar does not currently possess. The savings in this area were driven by these GPE capabilities and are only available to Westar in the savings estimation timeframe through the merger.

Q. Are there other key cost savings drivers Mr. Lesser does not address?

A. Yes. Mr. Lesser conveniently omits the first two and largest drivers of supply chain savings, specifically:

- "Sourcing from the best contracts of each company – prices, terms and conditions"; and
- "Rebidding duplicate contracts with increased volume – reduce vendor base"

These two savings drivers account for the vast majority of the Supply Chain savings and certainly are not accessible without the proposed Transaction. Without the proposed combination of GPE and Westar, neither stand-alone company would have access to detailed pricing, line items pricing details, terms and conditions of each contract, or supplier value added service offerings. Only with this detailed information can the best contract elements of from each company be identified, leveraged in negotiations, and used to achieve cost savings. Only through the proposed Transaction can GPE and Westar obtain and use this confidential supplier-to-customer information, which is critical to achieving the Supply Chain savings estimated in our analysis.

Q. Mr. Lesser contends, in pages 80-81 of his testimony, that since strategic sourcing is an established procurement tool, any company (including Westar or GPE) can independently apply strategic sourcing without any merger. Is it really that easy?

A. No. Mr. Lesser's testimony indicates a fundamental lack of understanding of the nature of strategic sourcing. He ignores the combined purchasing volume and aggregate supplier base that results only from the proposed combination of GPE and Westar. This is the major driver of the Supply Chain strategic sourcing savings identified in my direct testimony.

Mr. Lesser then contends in line 20 on page 80 to line 3 on page 81, that since strategic sourcing is an established procurement tool, that any company, specifically Westar or GPE, can independently apply strategic sourcing without any merger. His conclusion mischaracterizes my direct testimony and GPE's analysis, and is simply wrong. Strategic sourcing is a tool managers in any company can use to develop lower cost contracts, but the supply chain savings projected from this proposed Transaction can only be achieved through leveraging the increased purchasing scale per item and category, along with rationalizing the combined supplier base of both companies. Neither GPE nor Westar can use strategic sourcing or any other purchasing tools to achieve the level of savings estimated in our analysis without the combined spending levels and aggregate supplier base that results from combining. This linkage of scale with strategic sourcing benefits is widely acknowledged among experienced Supply Chain professionals.

Q. Do you disagree with any other supply chain related conclusions in Mr. Lesser's testimony

A. Yes. Mr. Lesser's conclusions on Supply Chain issues are wrong and misleading in at least three other areas: Wolf Creek, CapEx savings, and reduced inventory carrying costs.

Q. At page 83 line 16 through page 84 line 3 of this testimony, Mr. Lesser contends the supply chain savings projected for Wolf Creek could be achieved without the Transaction. Do you agree?

A. No. While Wolf Creek is jointly owned by Westar, GPE and other Kansas utilities, its operations are managed independently. For its Supply Chain operations, Wolf Creek uses Westar information technology and infrastructure with manual procurement tools and processes.

With the proposed Transaction, the resulting company can quickly implement advanced automation tools, advanced analytics and best practices across Westar as described above in this testimony, to create a common procurement platform across both companies. At that point, working with the minority owners and employees of Wolf Creek, improved procurement tools and practices can be quickly implemented and supported through the common procurement systems of the combined company and common procurement data structures and requirements. Without the procurement automation tools and associated purchasing practices changes, achieving significant savings at Wolf Creek will be very difficult, certainly will be significantly delayed, and will likely create additional procurement process risks. The projected Wolf Creek supply chain savings cannot be achieved without the Transaction.

Q. Mr. Lesser contends on page 84 lines 9-12 of this testimony that the proposed Supply Chain savings in capital expenditures and the related inventory carrying costs are overstated and not appropriate, *i.e.*, not resulting from the Transaction. Do you agree?

A. No. Reduced volumes on equipment in inventory, and lower capital costs for the such inventory are both clear benefits from the proposed Transaction. Each stand-alone company must maintain reserve equipment and inventory to not only meet normal operating needs and reliability support, but also provide additional reserve inventory and equipment needed to respond to external adverse events including weather, major infrastructure failures and catastrophic events. The levels of reserve inventory and equipment are driven by the need to respond to emergencies and contingent threats to system reliability, far more than overall inventory levels needed for normal operations. The reserve inventory and equipment will be much lower since reserve equipment and inventory can be shared across the combined company service territory. This allows the combined company to reduce its capital investments in reserve inventory and equipment while maintaining or improving service levels and reliability. This savings can only be achieved through the merger.

Capital expenditures are also reduced in the Supply Chain area due to the reductions in procurement costs discussed above. The major portion of the costs of material and equipment pulled from inventory ends up being capitalized as part of the cost of plant, so lower procurement costs reduce the capital expenditures that are required for the same capital investment programs.

Reductions in inventory levels and in the unit costs for the material and equipment acquired for inventory also reduce inventory carrying charges. Inventory carrying charges include both the cost of capital invested in inventory and the handling and warehousing costs for holding the inventory. These cost elements are reflected in revenue requirements and rates.

All projected Supply Chain savings from the proposed Transaction are a result of more efficiently meeting current operations standards, operating practices and GPE reliability goals, which are established under review and regulation by the Commission. These savings are neither speculative nor vague, but rather are driven by the operating demands of providing cost effective and reliable service levels.

Q. Does the utility industry have a track record of achieving such Supply Chain savings through mergers?

A. Yes. Many mergers have achieved each of the types of Supply Chain savings discussed above. In fact, GPE achieved the types of savings discussed above from their merger with Aquila, and exceeded the level of Supply Chain savings that it projected initially

7. SHARED SERVICES SAVINGS ESTIMATES

Q. Were GPE's bid process estimates of merger-related savings in the Shared Services area strongly criticized by Staff and intervenor witnesses?

A. No. My reading of the Staff and intervenor direct testimony is that the reasonableness of the level of estimated Shared Services savings was not strongly challenged. As shown in Schedule WJK-5, GPE's estimate of administrative and general ("A&G") savings (functionally equivalent to Shared Services) from the Transaction, if fully achieved, would place it in the third quartile of the range of cost reductions achieved in other utility

M&A transactions; *i.e.*, the level of Shared Services net savings, estimated at 6.5 percent, would be smaller than the median. GPE's initial estimates of Shared Services savings were conservative, well within the range of industry experience, and smaller than actually achieved in the Aquila transaction.

Some witnesses complained that not enough detail was available on how the savings were estimated. Regarding the timing of the detailed integration planning work, it is not unusual in transactions resulting from competitive bidding/ auction process to have integration work and regulatory proceedings conducted in parallel. Moreover, GPE conducted two workshops for Staff and intervenors to help them understand the derivation of the savings estimates, and respond to their questions.

The reasonableness of those assumptions and GPE's bid process estimates of Shared Services savings have been validated by the ongoing, more detailed work of its integration planning teams. As a result of this process, as stated in the Rebuttal Testimony of Steven Busser, the functional integration teams with responsibility for the Shared Services areas have reviewed and validated or modified the assumptions for the efficiencies developed pre-announcement. The integration teams have also found additional efficiencies in Shared Services, *e.g.*, in the non-labor costs. This integration planning work has increased GPE management's confidence that the estimated efficiencies from the Transaction will be achieved.

Q. As an example of the allegedly inadequate level of detail in GPE's bid process estimates of Shared Services savings, Staff witness Ann Diggs asserts on pages 36-40 of her direct testimony that GPE estimated the expected level of FTE reductions in various specific line items of Shared Services activities simply by applying high level percentages, rather than conducting in-depth analyses. Is this an accurate representation on GPE's estimation process?

A. No. GPE's sponsoring executives reviewed the available data on baseline FTE and dollar budget baselines (as documented in the merger savings workbook), discussed them with the Enovation Partners team and other GPE attendees at their interview sessions, considered the range of industry experience with A&G cost reductions after mergers, and then provided their estimated savings by line item. The savings estimates were captured during the interview sessions as hard inputs into the merger savings workbook. For the bulk of the Shared Services budget line items, those estimates were in the form of specific FTE headcount reductions across the combined companies. For many of the larger Shared Services functions, the executives elected to provide their estimates in the form of a percentage FTE headcount reduction. The examples that Ms. Diggs cites on page 38, line 7 through page 30, line 11 are from this latter category.

Q. Ms. Diggs, at page 41, line 7 through page 42, line 16 of her testimony, criticizes GPE's assumption on the average cost to achieve for FTE reductions in the Shared Service area, as well as the other functional savings area. Why does GPE still believe that its assumptions on labor-related costs to achieve are reasonable?

A. GPE used a general assumption in the bid estimates that the cost to achieve per FTE reduction would be 50% of the annual loaded labor cost per FTE for that budget line.

GPE views this as a conservative assumption, at the upper end of what its costs to achieve could be. 50% of the loaded labor cost is close to the average severance payments that GPE assumed in the bid process for the combined Westar and GPE workforces. The actual average cost per FTE is expected to be lower, since a large proportion of the FTE reductions (25% or more) will be accomplished without severance payments. As explained in Mr. Bassham's direct testimony, GPE will use attrition, relocation, and redeployment instead of severance payments wherever possible. The weighted average costs to achieve would roll in the lower cost attrition, relocation and redeployment options, as well as the severance payment option.

Q. Ms. Diggs points out page 42, lines 5-16 that GPE calculated the cost to achieve for FTE reductions achieved in 2017 as 50% of the budget line item's loaded labor costs for the 2017 half-year, rather than 50% of the loaded labor costs for the full year. Was this an error, and is it material?

A. It was indeed a calculation error. GPE should have used 50% of the loaded labor cost per FTE for the full year. However, the understatement of costs to achieve is not material, given the very significant conservatism built into the overall labor-related costs to achieve, as discussed in the preceding Q&A. Severance costs in 2018-2020, which represent the bulk of such costs, were calculatedly correctly using GPE's conservative (high) assumptions on the average cost per FTE reduction. GPE stands by its estimate of the overall labor-related costs to achieve.

Q. Messrs. Lesser (pages 36-37) and Steffen (pages 24-34) argue that GPE and Westar could achieve comparable levels of Shared Services savings without a merger, through sale of best practices, sharing of back office infrastructure, or outsourcing of Shared Services activities. Do you agree?

A. No. GPE and Westar are two respected, well-managed utilities, and they have voluntarily participated in numerous best practices consortia for many years. The regulatory regimes in which they operate create financial incentives for them to reduce O&M expenses, especially between general rate cases.

Nonetheless, for the reasons discussed at length in GPE's responses on the barriers to sharing of best practices (BPU Data Request No. 2-27[5], BPU Data Request No. 3-19[6], and BPU Data Request No. 5-2[7]), GPE and Westar have not sold or shared many internal best practices to other utilities. It is not realistic to assume, for purposes of enforcing an artificial "but for" hurdle, that they will suddenly begin to do so. Such sudden changes in long established business practices are not likely in the normal course of business.

Q. Have the KCC and other state regulatory commissions consistently accepted savings from consolidation of management structures and shared services functions as merger related?

A. Yes. Such scale economies are a core element of merger savings. They are frequently included in the category of "created" savings, which are directly due to the merger. The

[5] See Schedule WJK-10
[6] See Schedule WJK-11
[7] See Schedule WJK-12

combined company will not need two management structures, two Human Resource departments, two Finance groups, etc.

To argue that Shared Services savings are not benefits from the Transaction flies in the face of economic common sense, industry experience and regulatory precedent. As but one example, during the proceeding leading to KCC approval of GPE's acquisition of Aquila, Inc. in 2008, in which I was a witness and active participant, savings from management structure consolidation were unequivocally recognized as merger-related.

8. T&D & CUSTOMER SERVICE SAVINGS ESTIMATES

Q. Staff witness Walter Drabinski states at page 6, line 11 of his testimony that "T&D Staffing will decrease by 126 positions" due to the merger, citing his Exhibit WPD-1. Is this statement accurate?

A. No. Exhibit WPD-1 shows a Transmission and Distribution "(T&D") staffing reduction of 24 positions. Mr. Drabinski's testimony on page 6 is contrary to his exhibit and overstates T&D staffing reductions by over 400 percent.

Q. Mr. Drabinski asserts on page 8 of his testimony that full implementation of merger-related changes will reduce T&D O&M by 26%. Is this an accurate claim?

A. No. That percentage reduction in T&D Non-Fuel O&M ("NFOM") is overstated. Mr. Drabinski misreads GPE's testimony and workpapers. The T&D O&M costs in the annotated merger savings workbook (Schedule WJK-8), which he cites as his source for these numbers, include only those GPE and Westar budget line items that will see cost reductions from the merger. They do not represent the total T&D O&M budget.

The baseline "O&M Projection without Merger" shown for T&D in Exhibit WPD-2 understates very substantially the total budgeted O&M for the combined

company. Exhibit WPD-2 shows total T&D O&M in 2020 without the merger of about $17 million. That is an extremely small number for such a large system. The budget just for Vegetation Management, which Mr. Drabinski explicitly addressed in his testimony is about $60 million, or 3.5 times the size of his posited total T&D O&M budget. A comparison with Exhibit WJK-4 shows that his posited $17 million baseline T&D O&M budget was much too small. Exhibit WJK-4 shows that the actual T&D O&M cost in 2015 for the two companies combined was $544 million, based on their Form 1 filings with the Federal Energy Regulatory Commission ("FERC").

Mr. Drabinski understates the baseline T&D O&M costs by over 95 percent. The percentages calculated in Exhibit WPD-2 are clearly in error, as are his assertions on page 8.

Q. Messrs. Drabinski (pages 60-68) and Lesser (pages 75-79) conclude that the actions to achieve GPE's estimated T&D savings could threaten service reliability. Do you agree?

A. No. As I stated in my Direct Testimony, GPE was deliberately cautious and conservative in its approach to O&M savings in T&D. No reductions in field crew resources were assumed. Savings were limited to consolidation of certain central support functions and program management.

As shown on Schedule WJK-4, the T&D O&M cost reductions planned by GPE, before adding allocated supply chain savings, are only $4.3 million in 2020. This is a very small percentage of the T&D O&M budget, and should be very reasonably achievable without threatening reliability.

Q. Several witnesses expressed concern that Vegetation Management may be an activity that GPE plans to cut too deeply. See Mr. Lesser at page 76 and Mr. Drabinski at pages 66-67. Why is this not the case?

A. This small planned cut in contract management overhead is a good example of Staff and intervenor witnesses trying to create material issues where there are none. GPE did not assume in the bid phase savings estimates that any service levels in Vegetation Management contracts would be cut. We did assume that some minor savings in contract management would be possible, and that savings from consolidation of Vegetation Management contracts could be achieved. The total assumed savings for Vegetation Management, as stated in GPE's response to Staff Data Request No. 338[8], is about $3 million out of the combined companies' budget of approximately $60 million. As Mr. Busser testifies, maintaining – over time even improving - reliability is a foundational principle for GPE and its integration planning.

Q. Mr. Drabinski also asserts (pages 60-66) that the Distribution CapEx savings identified in GPE's estimates for the bid process are inconsistent with the objectives of Westar's proposed Electric Distribution Grid Resiliency ("EDGR") program. Does GPE support the objectives of EDGR?

A. Yes, GPE supports prudent measures to increase grid reliability. As GPE explained to an audience including Mr. Drabinski at the savings workshop on October 12, 2016, the increases in distribution capital expenditures requested by Westar for the EDGR program were not included in the baseline budget numbers that Westar provided and GPE used for the bid process savings estimates. GPE did not assume or propose any EDGR-related

[8] See Schedule WJK-13

increases in Distribution CapEx for Westar, or any reductions thereof. My understanding is that the EDGR program was not supported by Staff or approved by the Commission in Westar's most recent rate case.

GPE did include an estimate of Distribution CapEx savings that could be achieved if Westar's Distribution CapEx per customer is reduced to the same level as GPE. A number of opposing witnesses pointed out that the number of customers is not the only driver of Distribution CapEx. GPE does not dispute that other cost drivers are also important. The assumed level of Distribution CapEx reductions is illustrative of the level of savings that GPE assumed should be reasonably achievable when combining two large T&D systems.

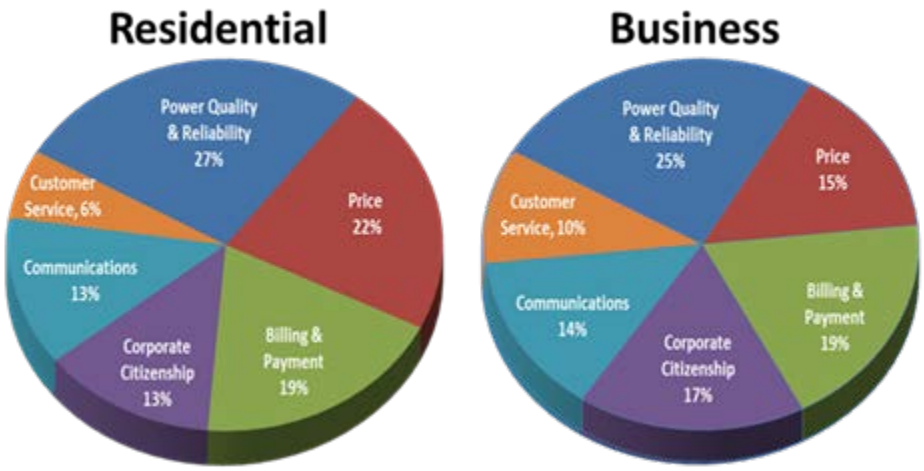
GPE reiterates its basic position on pursuing merger-related savings in the T&D and Customer Service areas, which is that it will be very conservative about any such cost reductions, so that reliability and customer satisfaction are not negatively affected.

Q. Is reliability the dominant driver of customer satisfaction for electric utilities?

A. No. While these are certainly important factors, other factors are also important. As explained in GPE's response to BPU Data Request No. 2-7[9], the physical attributes of electrical service (Power Quality and Reliability) account for only 27% of Residential customer satisfaction and 25% of Business customer satisfaction, according to JD Power. And Price accounts for only 22% and 15% of customer satisfaction for those groups, respectively.

[9] See Schedule WJK-14

Drivers of Electric Utility Customer Satisfaction



Source: JD Power

The combination of Billing & Payment, Corporate Citizenship, Communication and Customer Service accounts for the rest. The customer and community drivers together drive more than half of both Residential and Business customer satisfaction. As with other industries, customers increasingly value choice (*e.g.*, in billing and service options) and ease of doing business.

This context is useful for the broader picture on how the merger can provide significant customer benefits. Cost savings from the merger will produce price benefits for customers. But GPE also will ensure cost reductions do not erode the non-price drivers of customer satisfaction, such as reliability, customer service, and corporate citizenship by using a balanced scorecard approach to setting goals and measuring performance, so that the non-price drivers of customer satisfaction are appropriately addressed. That is the major reason for using a balanced scorecard approach. See GPE's response to BPU Data Request No. 2-7.

Q. Is GPE confident that it can achieve the estimated T&D/Customer Service savings from the Transaction?

A. Yes. As noted in the testimony of Mr. Busser, the functional integration teams with responsibility for the T&D and Customer Service areas have reviewed and validated or modified the assumptions for the efficiencies developed pre-announcement. The integration teams have found opportunities for additional efficiencies, but GPE will be conservative about implementing them.

9. UTILITY INDUSTRY EXPERIENCE WITH MERGER SAVINGS

Q. **Various Staff and intervenor witnesses criticize your summary of utility industry experience with cost changes associated with merger transactions. These include Ms. Diggs at pages 16-20, Mr. Steffen at pages 41-50 and Mr. Lesser at pages 41-50, and Mr. Kirsch at pages 32-42. What are your general responses to their critiques?**

A. First, the KCC and their peers in Missouri already accepted an earlier form of this same analysis in the KCP&L-Aquila merger approval case. The data set of comparable transactions was updated for the GPE-Westar case.

Second, it's hard to argue with actual cost data as reported to the Federal Energy Regulatory Commission ("FERC"). The data set comprises actual cost data reported according to the FERC Uniform System of Accounts. One may argue about what caused the changes (see below), but the costs are what they are. Using FERC's accounting system helps ensure comparability of reported cost data.

Third, the data set was constructed to capture the range of relevant industry experience. The transactions were not "cherry picked." We included all the large, enterprise level transactions that involved an electric utility. Experts can argue about

which data points should properly be excluded as irrelevant or outliers not plausibly reflecting merger influences, but the general patterns of cost changes over the post-merger period remain consistent.

Fourth, the data set was used for a limited purpose, *i.e.*, to compare inflation-adjusted percentage cost changes across the set of other relevant industry transactions. We were not conducting a "comparables" analysis for valuation purposes. Criticisms trying to hold our analysis to that standard are misplaced.

Fifth, the GPE team has already addressed the question of whether the cost changes experienced by merging utilities are due to factors other than the merger that would have affected all utilities, *e.g.*, general electric industry cost trends or economic cycles. See GPE response to Staff Data Request 32.[10] The average changes in real costs for merging utilities over the period from the calendar year before transaction close to the calendar year three years after close are consistently and often very substantially different (in a downward direction) than those for the group of all large non-merging utilities over the same four-year periods.[11] Involvement in a merger was clearly associated with greater cost reductions or lower cost increases.

Q. Ms. Diggs at page 22 of her testimony and Mr. Lester at pages 40-41 of his testimony assert that the finally realized savings from the KCP&L-Aquila transaction were not higher than the initial estimates. Are they correct?

A. No. It is true that the actual inflation-adjusted decrease in total non-fuel O&M costs in the three years following transaction close was slightly lower than the final savings

[10] See Schedule WJK-15

[11] "Non-merging" means not involved at all in a merger in the subject 1996-2010 period, or not involved in a merger for at least five years prior to the four-year period compared.

estimates filed with the Commission in the merger approval case. This was in large part due to GPE's willingness to step up and replenish the depleted ranks of Aquila's customer service function, at a higher than expected cost.

However, the initial estimates of non-fuel O&M savings (from early 2007) were significantly lower that the final estimates (from late 2007), again indicating that savings opportunities typically expand as you drill deeper. Furthermore, the initial savings estimates did not include interest savings on Aquila's debt or CapEx savings in the Supply Chain area. Both of these savings elements turned out to be substantial, and are not reflected in the non-fuel O&M savings, which is a narrower measure.

The finally realized savings from the KCP&L-Aquila transaction were indeed significantly higher than initially estimated.

Q. Mr. Lesser, at pages 49-50 of his testimony, criticizes the validity of the "Sales" numbers that are included in the database of reported utility O&M costs that underlies Schedule WJK-5. Is this another example of Mr. Lester mischaracterizing your testimony?

A. Yes. As stated in my Direct Testimony at page 30, the "Sales" numbers included in the database of reported utility O&M costs merger savings database are the costs of the Sales function, as reported in the FERC O&M cost accounts for Sales. This covers FERC O&M accounts 911 through 917. GPE did not include utility Sales O&M numbers in its analysis of merger-related cost changes because they are very small and driven more by sales initiatives and accounting policies than by O&M cost fundamentals. Mr. Lesser instead assumed that the "Sales" numbers represented some type of revenue metric, which is clearly incorrect.

Q. Mr. Lesser at page 42, lines 8-9 of his testimony, states that some values in the table of percentage cost changes for the transactions in your merger savings database are missing or shown as "N". Did Mr. Lesser have explanations from GPE for why data in those cells were not included?

A. Yes. In its response to BPU Data Request no. 3-4[12], GPE explained why each of the cells in question was excluded from the analysis. The reasons included no reported costs in that function before or after the Transaction (*e.g.*, no reported Generation Non-Fuel O&M costs due to generation asset divestiture), other structural changes (*e.g.*, very large increases in Transmission O&M costs due to start-up of a new Independent System Operator), or extreme values that were well outside of the range that could plausibly be merger-related effects and were more likely driven by accounting changes (*e.g.*, a 282% increase in Customer Service costs).

The workpaper provided in GPE's amended response to BPU Data Request 3-1[13] also showed explanations for the blank (zero cost) and "N" (outlier) cells.

Again, GPE's intent was to include all relevant transactions and related cost change data, while taking out statistical noise in the form of values that were not relevant to an analysis of merger-related cost changes. GPE was not trying to analyze the cost impact from industry restructuring.

Q. What are the implications of the consolidation trend in the U.S. electric utility industry?

A. The market reality is that the U.S. electric utility industry is consolidating. The number of investor-owned U.S. electric utilities has shrunk by about 60 percent in the past twenty

[12] See Schedule WJK-16
[13] See Schedule WJK-17

years. As was evidenced in the interest from both utility and financial buyers in the Westar auction process, quality acquisition candidates are in high demand. This movement toward consolidation reflects is strong evidence that industry players recognize and value the fundamental scale economies that can be achieved.

Q. What are the most important insights that the KCC can draw from GPE's analysis of the experience of the industry with merger-related cost changes?

A. The major insights from GPE's analysis of industry experience with merger-related cost changes include:

- Estimated savings from the proposed GPE-Westar transaction are about where you would expect, based on industry experience and the characteristics of this particular transaction. They are neither a sandbag nor a stretch.
- Selling shareholders (in the short term) and customers (in the longer term) have been the consistent winners in utility mergers. As long as GPE can demonstrate that its financial health will remain strong, the allocation of benefits support the Joint Applicants' assertion that the Transaction is in the public interest.
- The specific experience of GPE should give the KCC comfort. GPE has the proven ability to deliver on its targeted level of merger benefits.
- Finally, when trying to place the Transaction in context with other relevant electric utility mergers, there is a lot of statistical noise. But my experience and that of Mr. Flaherty indicates that this is the type of deal that succeeds in delivering above normal results. The other potential buyers for Westar in its sale process would have been more likely to encounter difficulties in achieving similarly favorable results.

10. CONCLUSIONS

Q: Could you please summarize the major conclusions of this Rebuttal Testimony?

A. My major conclusions are as follows:

- GPE stands by its estimates of total savings from the Transaction. The initial savings estimates developed during the bid phase have been reviewed and validated by the work of the integration planning teams since June 2016, with some shifts among categories as more detailed analyses were completed. The integration teams have also found opportunities for additional efficiencies, which is to be expected as they deepen their understanding. GPE management is more, not less, confident that total estimated efficiencies from the Transaction will be achieved.
  - GPE's estimates of the savings from accelerated retirement of representative generation plants are reasonable and well documented. They reflect capital and O&M savings that neither utility planned to achieve separately. Staff and intervenor estimates of the cost to achieve these savings are grossly overstated and unreliable, due to their mistaken assumptions, outdated data, and incomplete analyses.
  - GPE's estimates of Supply Chain savings from the Transaction were not seriously challenged. Assertions by Staff and intervenor witnesses that GPE and Westar could achieve comparable savings without combining indicate a fundamental misunderstanding of the scale economies that drive modern supply chain management. GPE achieved Supply Chain savings in the KCP&L-Aquila transaction that were substantially higher than initially

estimated, using an approach similar to that assumed in the GPE-Westar savings analysis.

  - GPE's estimates of Shared Services savings from the merger are conservative and robust. Scale economies in Shared Services are a core element of merger savings. To argue that Shared Services savings are not benefits from the Transaction flies in the face of economic common sense, industry experience and regulatory precedent.
  - GPE's estimated savings in the T&D and Customer Service areas are not large, because GPE is taking a very conservative approach to any such cost reductions, so that reliability and customer satisfaction are not negatively affected. The combined company obviously would abide by the Commission's decisions on any reliability enhancement programs.

- Staff and intervenor witnesses have taken overly adversarial positions that lie far outside of accepted industry practice or indeed established KCC precedents. They argue for very narrow, artificial criteria for counting customer benefits. The "but for" test may sound plausible, but it would be very difficult to apply, would require acceptance of unproven hypotheticals on alternative paths to savings, and can easily lead toward an unproductive defense of the status quo.
- GPE counted only operational and capital cost savings that were attributable to the Transaction, *i.e.*, they were directly created or enabled by the Transaction, and could not be realized in the normal course of business as separate companies. This standard is close in practice to that used by the U.S. Department of Justice, which counts

savings as merger related if they are likely to be achieved with the merger and unlikely without.

- No witnesses have contradicted the fact the estimated total savings from the Transaction are generally consistent with the middle of the range of what has been achieved from similarly situated mergers. This squares with the broad, real world experience of Mr. Flaherty and myself in advising on utility mergers, and with GPE's track record in the Aquila acquisition. GPE's savings estimates are conservative and reasonable, and GPE is committed to achieve them.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for approval of the Acquisition of Westar Energy, Inc. by Great Plains Energy Incorporated	)))))	**Docket No. 16-KCPE-593-ACQ**

AFFIDAVIT OF WILLIAM J. KEMP

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

William J. Kemp, being first duly sworn on his oath, states:

1. My name is William J. Kemp. I am a Founder and Senior Managing Director at Enovation Partners, LLC. My company's headquarters are in Chicago, Illinois.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Great Plains Energy Incorporated and Kansas City Power & Light Company consisting of fifty-seven (57) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

William J. Kemp

Subscribed and sworn before me this 9th day of January 2017.

Notary Public

My commission expires: Feb. 4 2019

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2019
Commission Number: 14391200

SCHEDULE WJK-3R

ESTIMATED TRANSACTION SAVINGS

(based on analyses performed in support of GPE's bid)

$million	Gross Savings				Costs to Achieve				Net Savings				
	2017 (1)	**2018**	**2019**	**2020**	**2017** (1)	**2018**	**2019**	**2020**	**2017** (1)	**2018**	**2019**	**2020**	**2021+ (3)**
NFOM Expense													
Generation	3	6	61	79	1		28	9	1	6	33	70	80
T&D / CS	2	5	5	5	1				1	5	5	5	5
Shared Services	10	23	24	24	5	2	2	1	5	21	22	23	25
Supply Chain	12	22	66	66	8	2	2	2	5	20	64	64	65
Total NFOM	28	55	155	174	16	3	31	12	12	52	124	162	176
Capital (2)	3	11	25	36	-	-	-	-	3	11	25	36	
Total	**30**	**66**	**180**	**210**	**16**	**3**	**31**	**12**	**15**	**63**	**149**	**199**	**176**

(1) Assumed Jul-Dec 2017

(2) Revenue requirement impact of capital expenditure reduction

(3) Annual savings after 2020 were not projected for GPE's bid, but minimal additional costs to achieve would be expected, and gross annual NFOM savings would be expected to increase at roughly the rate of inflation. Capital-related savings would decline after 2020 and have not been quantified.

Source: GPE savings estimates

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20160928
Date of Response:

Question:2-5

Referring to table in the Direct Testimony of William Kemp, at 10:4-7:

1. Please state whether the savings estimates prepared by Mr. Kemp were solely based on EP's database.

2. Please provide all supporting documents, analyses, and workpapers prepared by Mr. Kemp, or under his supervision, to justify the GPE savings analysis.

RESPONSE: (do not edit or delete this line or anything above this)

1. The referenced testimony does not discuss any specific savings estimates, but rather a "reasonable set of expectations around potential percentage levels of transaction savings in various major utility functions and overall." In this context, the percentage levels of real cost changes (savings) in comparable transactions were based on EP's database, which was in turn based on FERC Form 1 data.

2. See the response to BPU Data Request 2-4, which (with the referenced other data responses) provides the underlying data on comparable transactions that was used for the March 2016 contextual analysis and to develop Schedule WJK-5.

Attachment: Q2-5_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 2-5, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: October 11, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Grady Justin Interrogatories - KCC_20160923
Date of Response:

Question:135

In response to Staff Data Request No. 7, KCPL provided a spreadsheet model entitled "Q7_CONF_Workpaper_Merger Savings Model_5-14-18". This model contains very few active formulas or links that make it possible to navigate through and understand the model. Please provide a revised version of this spreadsheet in its native form, with all formulas, links, etc. intact.

RESPONSE: (do not edit or delete this line or anything above this)

See the attached workpaper "Q7_CONF_Workpaper_Merger Savings Model_5-14-16_Annotated." The pivot table logic and source data links in the Summary sheet have been restored. The formulas and pivot table functionality in the Data sheet have either been restored (gray cells) or the sources for the pivot table data have been noted.

The input sheets were not changed, as the data there are easier to follow.

This additional information should help staff understand the workbook.

Attachment: Q135_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 135, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: October 7, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Grady Justin Interrogatories - KCC_20160923
Date of Response:

Question:135A

Amended:

In response to Staff Data Request No. 7, KCPL provided a spreadsheet model entitled "Q7_CONF_Workpaper_Merger Savings Model_5-14-18". This model contains very few active formulas or links that make it possible to navigate through and understand the model. Please provide a revised version of this spreadsheet in its native form, with all formulas, links, etc. intact.

RESPONSE: (do not edit or delete this line or anything above this)

This amended response provides the location of the identified workpaper. No other changes have been made to the response.

See workpaper "Q7_CONF_Workpaper_Merger Savings Model_5-14-16_Annotated" attached to GPE's response to KCC Staff Data Request No. 134. The pivot table logic and source data links in the Summary sheet have been restored. The formulas and pivot table functionality in the Data sheet have either been restored (gray cells) or the sources for the pivot table data have been noted.

The input sheets were not changed, as the data there are easier to follow.

This additional information should help staff understand the workbook.

Attachment: Q135_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 135A, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

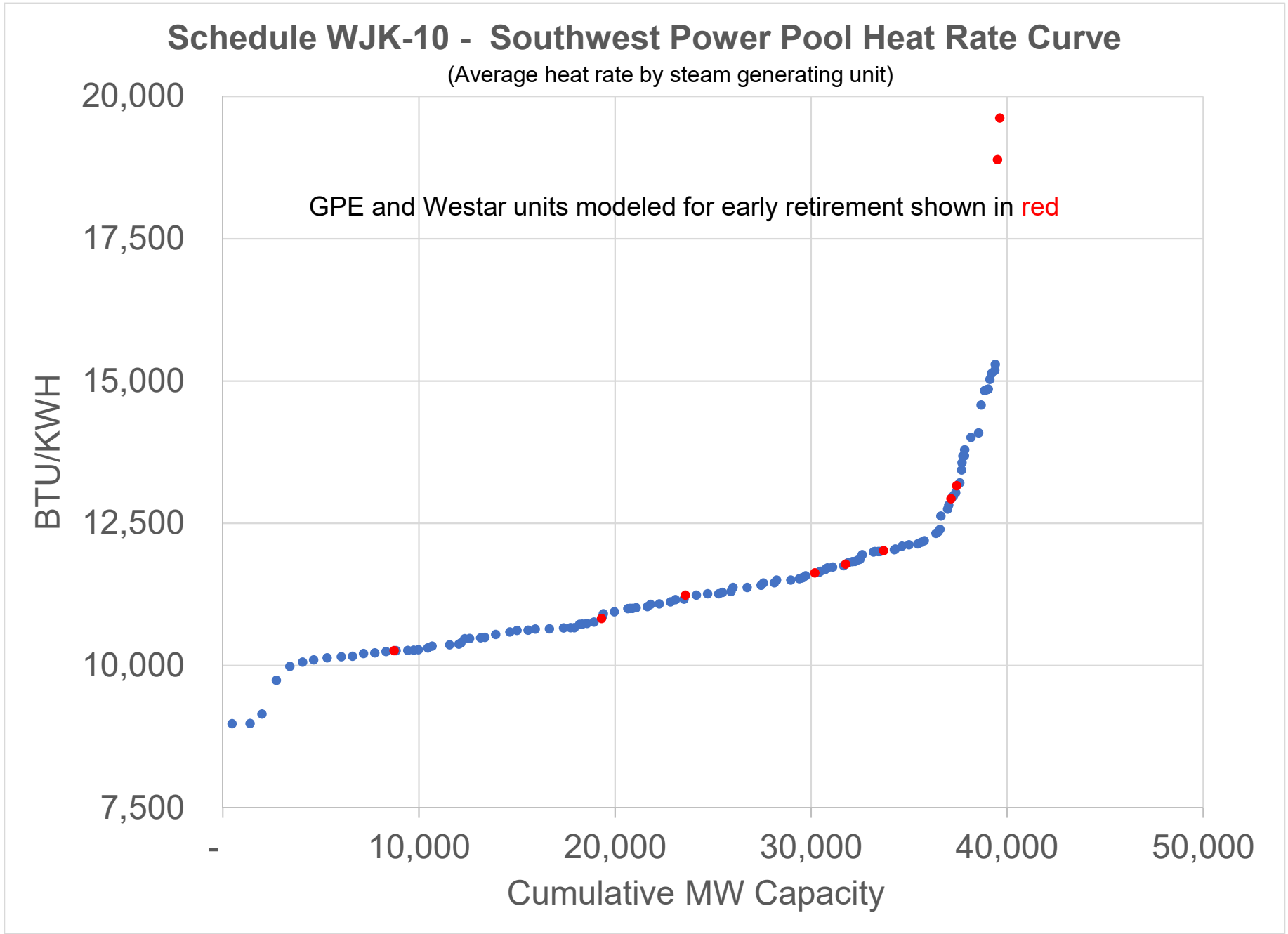
Title: Senior Managing Director

Date: November 14, 2016

Wizard Capacity and Load Balance - Wind Capacity Adjusted, No Sky Retirements
4/29/2016
DRAFT

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
LOADS																			
Wizard Projected Combined Internal Demand	**11,197**	**11,294**	**11,374**	**11,452**	**11,524**	**11,611**	**11,697**	**11,791**	**11,867**	**11,946**	**12,036**	**12,140**	**12,230**	**12,321**	**12,414**	**12,506**	**12,597**	**12,692**	
DSM (KCP&L)	43	79	105	142	171	193	214	231	249	264	273	281	289	298	301	305	309	313	
DSM (GMO)	66	99	136	192	249	307	364	420	445	469	491	512	532	549	565	581	596	610	
DSM (Sky)	240	236	233	227	222	218	215	212	209	207	205	204	203	202	201	200	199	198	
Total DSM	**349**	**415**	**474**	**561**	**642**	**718**	**793**	**862**	**904**	**940**	**969**	**997**	**1,024**	**1,049**	**1,067**	**1,086**	**1,104**	**1,122**	
Peak Responsibility (Combined Demand Forecast)	**10,848**	**10,879**	**10,900**	**10,891**	**10,882**	**10,893**	**10,904**	**10,928**	**10,963**	**11,006**	**11,068**	**11,143**	**11,206**	**11,272**	**11,347**	**11,420**	**11,493**	**11,570**	
Capacity Responsibility (inc. 12% Reserve Margin)	**12,150**	**12,185**	**12,207**	**12,198**	**12,188**	**12,201**	**12,213**	**12,240**	**12,278**	**12,327**	**12,396**	**12,480**	**12,550**	**12,625**	**12,708**	**12,790**	**12,872**	**12,958**	
CAPACITY																			
Existing Generating Capacity (Combined share):																			
KCPL	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	
GMO	2,087	2,087	2,087	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	
SKY	6,083	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	6,098	Adjusted to increase owned wind accredited capacitry to 30%
Total Existing Generating Capacity	**12,530**	**12,545**	**12,545**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	**12,579**	
Purchases :																			
KCPL (wind, hydro)	335	335	335	335	335	335	335	273	273	273	273	273	273	273	273	273	273	273	
GMO (wind)	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	
SKY (wind, McPherson, KEPCo, State Line, KEPCo Hydro)	1,073	1,073	1,073	1,073	1,073	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,037	1,037	1,032	1,032	1,032	1,032	Adjusted to increase PPA wind accredited capacitry to 30%
Total Capacity Purchases	**1,504**	**1,504**	**1,504**	**1,504**	**1,504**	**1,488**	**1,488**	**1,427**	**1,427**	**1,427**	**1,427**	**1,427**	**1,407**	**1,407**	**1,402**	**1,402**	**1,402**	**1,402**	
Sales:																			
KCPL	(52)	(52)	(42)	(42)	(15)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	
GMO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
SKY	(426)	(426)	(254)	(254)	(209)	(209)	(150)	(150)	-	-	-	-	-	-	-	-	-	-	
Total Capacity Sales	**(478)**	**(478)**	**(296)**	**(296)**	**(224)**	**(224)**	**(150)**	**(150)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
TOTAL NET ACCREDITED CAPACITY (Existing Resources)	**13,556**	**13,571**	**13,753**	**13,787**	**13,859**	**13,843**	**13,917**	**13,856**	**14,006**	**14,006**	**14,006**	**14,006**	**13,986**	**13,986**	**13,981**	**13,981**	**13,981**	**13,981**	
PLANNED CAPACITY UNDER DEVELOPMENT																			
KCPL	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
GMO	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
SKY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Planned Additions	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	
NET CAPACITY POSITION (Short) - No Retirements	**1,408**	**1,387**	**1,547**	**1,590**	**1,672**	**1,643**	**1,705**	**1,617**	**1,728**	**1,681**	**1,612**	**1,528**	**1,437**	**1,362**	**1,274**	**1,192**	**1,111**	**1,025**	
RESERVE MARGIN No Retirements- Wizard	**25.0%**	**24.8%**	**26.2%**	**26.6%**	**27.4%**	**27.1%**	**27.6%**	**26.8%**	**27.8%**	**27.3%**	**26.6%**	**25.7%**	**24.8%**	**24.1%**	**23.2%**	**22.4%**	**21.7%**	**20.9%**	
KCPL Reserve Margin - No Retirements	23.2%	23.3%	23.7%	24.3%	25.6%	25.6%	25.8%	23.8%	23.6%	23.5%	22.9%	22.0%	21.4%	20.7%	20.0%	19.3%	18.7%	17.9%	
GMO Reserve Margin - No Retirements	8.2%	9.3%	10.9%	15.5%	18.3%	21.3%	24.5%	27.6%	29.1%	30.2%	30.8%	31.2%	31.9%	32.3%	32.5%	32.6%	32.8%	32.9%	
Sky Reserve Margin - No Retirements	32.9%	31.7%	33.7%	32.2%	31.6%	30.0%	29.8%	28.5%	30.0%	28.8%	27.6%	26.4%	24.9%	23.8%	22.6%	21.5%	20.4%	19.3%	
Potential Retirements																			
Total Retirements - Cumulative	255	255	1,166	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	
RESERVE MARGIN With Retirements - Wizard	**22.6%**	**22.4%**	**15.5%**	**12.6%**	**13.3%**	**13.0%**	**13.6%**	**12.8%**	**13.8%**	**13.4%**	**12.7%**	**12.0%**	**11.2%**	**10.5%**	**9.7%**	**9.0%**	**8.4%**	**7.6%**	
NET CAPACITY POSITION (Short) With Retirements	**1,153**	**1,132**	**381**	**60**	**142**	**113**	**175**	**87**	**198**	**151**	**82**	**(2)**	**(93)**	**(168)**	**(256)**	**(338)**	**(419)**	**(505)**	

Retirements	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
GordonEvansEnergyCenter E1CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GordonEvansEnergyCenter E2CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GordonEvansEnergyCenter E3CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GordonEvansEnergyCenter GEV1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GordonEvansEnergyCenter GEV2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LawrenceEnergyCenter LEC4	0	0	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
LawrenceEnergyCenter LEC5	0	0	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Murray Gill Energy Center MGL3	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Murray Gill Energy Center MGL4	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
Tecumseh Energy Center TEC7	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Montrose 2	0	0	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164
Montrose 3	0	0	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176
Sibley 1	0	0	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8	49.8
Sibley 2	0	0	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1
Sibley 3	0	0	0	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1	364.1
Lake Road 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Road 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Road 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Road 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Road 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Road 6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Road 7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0


Schedule WJK-10 - Southwest Power Pool Heat Rate Curve
(Average heat rate by steam generating unit)
GPE and Westar units modeled for early retirement shown in red
BTU/KWH
20,000
17,500
15,000
12,500
10,000
7,500
-
10,000
20,000
30,000
40,000
50,000
Cumulative MW Capacity

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20160928
Date of Response:

Question:2-27

Referring to the Direct Testimony of William Kemp at 23:13-14, please:

1. Identify and define all best practices currently in place by each of the Joint Applicants individually.

2. Identify all legal/regulatory prohibitions against "best practice" sharing, as Mr. Kemp defines that term, by the Joint Applicants today.

3. Identify the estimated savings from best practice sharing and include all supporting documents, workpapers, and analyses estimating this cost of capital reduction.

RESPONSE: (do not edit or delete this line or anything above this)

1. Mr. Kemp has not conducted a study of the best practices currently in place.

2. Mr. Kemp has not taken a position on legal/regulatory prohibitions against best practice sharing. He is aware of benchmarking groups to which GPE and/or Westar belong, which contain some elements of best practice sharing. However, due to the competition that currently exists between GPE and Westar in some areas of their business (e.g., financing, customers, power marketing), natural barriers to sharing of best practices still exist.

3. Mr. Kemp assumes that the last phrase in this part ("estimating this cost of capital reduction") should be stricken.

   The savings from sharing of best practices (or "better" practices if only between the two firms) were estimated explicitly only in a few of the areas of opportunity, due to the time and information limits in the bid preparation process. See for example the upper part of the Supply Chain sheet in annotated merger savings workbook provided in response to BPU Data Request 2-2, which lays out estimates of savings from applying GPE's Supply Chain practices to Westar. See also the T&D Capex sheet in the same workbook, for the estimated capex savings from extending GPE's T&D capital spending practices to Westar. No doubt of the best practice sharing in the final integration of the firms would work in the other direction, from Westar to GPE.

Attachment: Q2-27_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 2-27, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: October 11, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20161107
Date of Response:

Question:3-19

In reference to the response to BPU-2-27(2), please:

1. Define the term "natural barriers to sharing best practices" as Mr. Kemp uses that term.

2. Identify each "natural barrier" that Mr. Kemp determined to exist and the basis for that determination.

3. Please describe how GPE and Westar compete for customers, power marketing, and finances.

4. Identify all areas of business in which Mr. Kemp has confirmed that GPE and Westar cannot share best practices. For each area identified, provide the specific reasons that best practices cannot be shared but for the merger.

5. Provide all data, analyses, and workpapers that support Mr. Kemp's response to this information request.

RESPONSE: (do not edit or delete this line or anything above this)

1. The term "natural barriers to sharing best practices" refers to organizational or competitive impediments to sharing sensitive information.

2. Mr. Kemp has not performed an exhaustive study of such natural barriers. The referenced response to BPU Data Request No. 2-27(2) lists some prominent examples. The companies also compete for human resource talent and for favorable vendor contracts, to name a couple of other examples.

3. GPE and Westar compete for customers directly through economic development efforts involving recruitment of industrial or commercial customers, and indirectly through yardstick competition around such metrics as customer satisfaction. They compete in the power marketing area in their efforts to secure more favorable wholesale power sales or purchase contracts. They and their utility peers compete for access to equity or debt capital on favorable terms.

4. Mr. Kemp has not performed an exhaustive study of the areas in which GPE and Westar cannot share best practices. For a variety of reasons, including those cited in parts 2 and 3 above, utilities may choose not to share best practice details or other sensitive information.

   It should be noted that both GPE and Westar have long participated in various utility benchmarking consortia, which are a form of sharing best practice information. The

effects of such past sharing to date were already baked into the baseline budgets which formed the starting point for the merger savings analyses.

Mr. Kemp has not performed "but for" analyses.

5. Mr. Kemp did not rely upon a quantitative analysis to formulate his response to this data request. He relied primarily on his long experience in working with utility management teams and assisting in various benchmarking and best practice assessment efforts in the industry.

Attachment: Q3-19_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to BPU Data Request# 3-19, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: November 14, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20161115
Date of Response:

Question:5-2

In reference to the response to BPU-2-33:

1. Please identify all ways in which KCPL and Westar currently compete for financing. Provide all specific examples of such competition for financing that has taken place over the last five years. Please identify all specific best practices, as that term is defined by Mr. Kemp, that cannot be implemented because of such competition in finance.

2. Please identify all ways in which KCPL and Westar currently compete for customers, and identify all specific customers over which the two utilities have competed for in the last five years. Please identify all of the specific best practices that cannot be implemented because of such competition for customers.

3. Please identify all ways in which KCPL and Westar currently compete in power marketing. Please identify all of the specific best practices that cannot be implemented because of such competition in power marketing.

4. For the responses to parts (1) – (3), include all supporting data/workpapers/analyses.

RESPONSE: (do not edit or delete this line or anything above this)

1. GPE and Westar compete for both debt and equity financing with each other, with other utilities, and with other types of firms. Companies who need external capital try to raise it at the lowest possible cost (e.g., lower interest rates on debt or higher prices per share for equity), which means convincing investors and the debt or equity analysts who advise them that your company has lower risks for debt or offers superior returns on equity than other comparable companies. Such competition for financing is an essential feature of capital markets.

   GPE does not believe that a list of "all specific examples of such competition for financing that has taken place over the last five years" is necessary to demonstrate that GPE and Westar compete for financing. GPE directs BPU to the following types of public documents produced by each company, which provide numerous examples:
   - SEC filings, especially registration statements for new equity offerings. Also forms 10-K and 10-Q, which summarize historical and projected financial performance.
   - Quarterly earnings materials that support Webcasts each quarter with interested investors and analysts, to review financial performance for the recently closed quarter and lay out future prospects
   - Annual reports to investors

- Presentations to investor conferences such as the annual EEI Financial Forum, the most recent of which occurred in early November 2016. North American and European electric utilities explicitly compete in such venues to improve the terms of their financing, through large numbers of parallel private and public meetings with investors and debt or equity analysts. Each utility seeks to portray its risk profile and growth prospects in the most favorable light, vs. its peers

The main types of best practices whose sharing would be discouraged by competition for financing are in the areas of treasury and investor relations

2. Since they are regulated utilities with monopoly retail service territories, GPE and Westar do not compete directly for existing retail electric customers. They do compete for wholesale customers, as explained below in part 3.

   GPE and Westar compete for new customers through economic development efforts involving recruitment of industrial or commercial customers who can increase electricity sales and generate other new customers through economic multiplier effects. Such economic development efforts are typically conducted jointly or in support of local or regional governmental agencies. The details of specific economic development incentive packages are generally kept confidential in competitive siting processes.

   GPE and Westar, and other utilities, also compete indirectly in the area of customer satisfaction. The yardstick competition among utilities in customer satisfaction rankings such as those published by JD Power can be quite intense.

   The main types of best practices whose sharing would be discouraged by competition for customers are in the areas of commercial/industrial customer recruitment, customer satisfaction analysis, customer communications, and customer strategy.

3. As related to power marketing activity, GPE and Westar compete in three different ways:
   - First, we compete as buyers. Both companies purchase or acquire the same goods and many of the same services for use in providing services to our respective customers.
   - Second, we compete as sellers. That is, both GPE and Westar sell power and are within sufficient proximity to one another as to be competitive alternatives to some customers, e.g. municipal utilities or cooperatives who procure wholesale power through competitive contracting.
   - The third way is a combination of both buying and selling. Both GPE and Westar engage in non-regulated power trading. As power traders, both companies engage in both buy and sell transactions. Westar and GPE have identified contracts, market approach and strategies as a boundary until Post Day-1.

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to BPU Data Request# 5-2, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: November 28, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Figgs Katie Interrogatories - KCC_20161102
Date of Response:

Question:338

Please reference the GPE Merger Savings Model ("Q7_CONF_Workpaper_Merger Savings Model_5-14-18_annotated") located within the "Data" tab on row 64 ("Westar Vegetation Management"). Please provide a detailed description supporting the unburned $/FTE cost of $242,862 per year under column "AD".

RESPONSE: (do not edit or delete this line or anything above this)

This information including the question itself is considered **CONFIDENTIAL** as it contains strategies employed, to be employed, or under consideration.

- Westar's total annual budget for Vegetation Management was assumed to be $33.5 million. See row 24 of the Sky O&M tab in the merger savings workbook.
- The Reliabilitree contract cost was assumed to represent 89% of the total Vegetation Management budget, leaving $3.8 million for the non-contract portion of that budget.
- GPE assumed that the non-contract portion of the Vegetation Management budget was 90%, or about $3.4 million.
- GPE's information from Westar indicated an internal Westar staffing level of 14 in that department.
- $3.4 million divided by the budgeted 14 FTE equals the $243k per year cost shown in column AD.
- GPE notes that although the $243k per FTE may appear high, the budgeted FTE denominator does not include contractor FTEs. The estimated savings of $3 million per year in Vegetation Management is reasonable and conservative compared with the combined annual Vegetation Management budget that was assumed to be close to $60 million.

Attachment: Q338_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 338, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: November 9, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Figgs Katie Interrogatories - KCC_20161102
Date of Response:

Question:338A

AMENDED:

Please reference the GPE Merger Savings Model ("Q7_CONF_Workpaper_Merger Savings Model_5-14-18_annotated") located within the "Data" tab on row 64 ("Westar Vegetation Management"). Please provide a detailed description supporting the unburned $/FTE cost of $242,862 per year under column "AD".

RESPONSE: (do not edit or delete this line or anything above this)

This response is to amend the percentage in the third bullet from 90% to 10%. No other changes were made.

This information including the question itself is considered **CONFIDENTIAL** as it contains strategies employed, to be employed, or under consideration.

- Westar's total annual budget for Vegetation Management was assumed to be $33.5 million. See row 24 of the Sky O&M tab in the merger savings workbook.
- The Reliabilitree contract cost was assumed to represent 89% of the total Vegetation Management budget, leaving $3.8 million for the non-contract portion of that budget.
- GPE assumed that the non-contract portion of the Vegetation Management budget was 10%, or about $3.4 million.
- GPE's information from Westar indicated an internal Westar staffing level of 14 in that department.
- $3.4 million divided by the budgeted 14 FTE equals the $243k per year cost shown in column AD.
- GPE notes that although the $243k per FTE may appear high, the budgeted FTE denominator does not include contractor FTEs. The estimated savings of $3 million per year in Vegetation Management is reasonable and conservative compared with the combined annual Vegetation Management budget that was assumed to be close to $60 million.

Attachment: Q338A_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 338A, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: November 14, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20160928
Date of Response:

Question:2-7

Referring to the Direct Testimony of William Kemp, at 11:1-15, please:

1. Define the term "balanced scorecard approach."

2. Provide Mr. Kemp's understanding of how GPE will empirically measure "the balanced nature of GPE's strategic intent" and provide all supporting workpapers, documents, and analyses related to that measurement.

3. Explain Mr. Kemp's understanding of how GPE will ensure cost reductions do "not erode the non-price drivers of customer satisfaction, such as reliability, customer service, and corporate citizenship." Provide all workpapers, documents, and analyses related to "non-price drivers" and specifically define the quantitative measures and basis for all such "non-price drivers."

4. Explain how "the teams performing the savings analyses kept these broader strategic perspectives in mind, in prioritizing cost savings areas and evaluating prudent level of cost reductions."

5. Please provide all workpapers, documents, communications and analyses related to "prioritizing cost savings areas and evaluating the prudent level of cost reductions."

6. Identify the person most knowledgeable on how GPE used the materials referenced in the cited portion of Mr. Kemp's testimony.

RESPONSE: (do not edit or delete this line or anything above this)

1. The term "balanced scorecard approach" is typically used to mean a system of high level performance metrics that track performance across of number of key financial and non-financial (e.g., customer, employee or growth) dimensions.

   This approach has been widely used in management for decades. Numerous definitions can be found on the Web. For example, Wikipedia's definition is:

   > "The **balanced scorecard** (**BSC**) is a strategy performance management tool – a semi-standard structured report, supported by design methods and automation tools, that can be used by managers to keep track of the execution of activities by the staff within their control and to monitor the consequences arising from these actions.
   >
   > The phrase 'balanced scorecard' is commonly used in two broad forms:
   >
   > 1. As individual scorecards that contain measures to manage performance, those scorecards may be operational or have a more strategic intent; and

2. As a Strategic Management System, as originally defined by Kaplan & Norton.

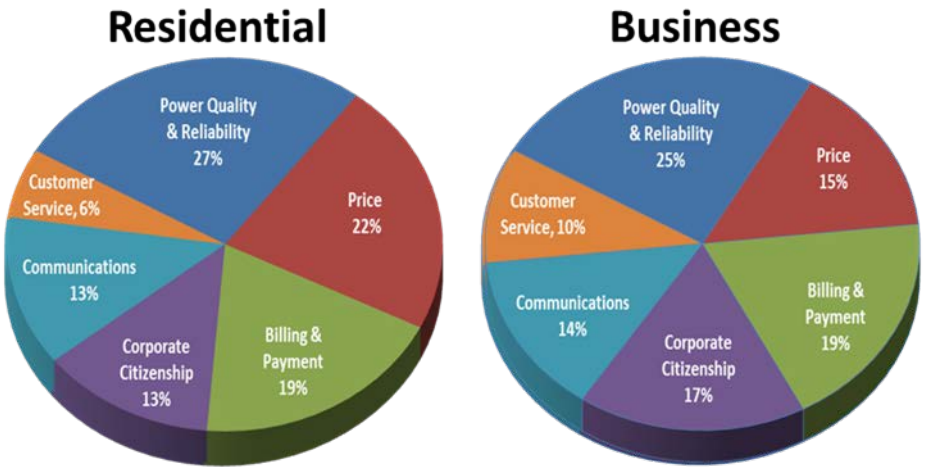
The critical characteristics that define a balanced scorecard are:

- its focus on the strategic agenda of the organization concerned
- the selection of a small number of data items to monitor
- a mix of financial and non-financial data items."

2. As discussed on page 10, lines 20-22 of Mr. Kemp's testimony, GPE has already established four major strategic initiatives, addressing the financial, customer, growth, and employee dimensions of its performance. He understands that GPE track its overall performance and that of its senior executives across these initiatives, but he is not familiar with the details of this internal process.

3. GPE will ensure cost reductions do not erode the non-price drivers of customer satisfaction, such as reliability, customer service, and corporate citizenship by using a balanced scorecard approach to setting goals and measuring performance, so that the non-price drivers of customer satisfaction are appropriately addressed. That is the whole point of using a balanced scorecard approach.

   Mr. Kemp did not develop any workpapers or analyses to describe or quantify non-price drivers, but firms that measure customer satisfaction (e.g., JD Power) have readily available data on the relative importance of the various drivers for customer satisfaction in the utility industry. For example, JD Power broke down the drivers of residential and business customer satisfaction in the utility industry as follows, as of 2014:



4. As explained in the preceding paragraph, Page 11 lines 8-12, they kept a balanced perspective. Perhaps the best example is the conservative approach to savings

initiatives in areas important for non-price drivers of customer satisfaction is described on page 23, lines 1-12 of Mr. Kemp's testimony.

5. See Mr. Kemp's testimony and supporting workpapers that have been provided to or referenced for BPU.

6. Terry Bassham (CEO) and Kevin Bryant (CFO) set the policies around the balanced scorecard. Steve Busser (Controller) is responsible for accumulating and reporting data on scorecard results. Each officer is responsible for the scorecard results as they pertain to his or her area.

Attachment: Q2-7_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 2-7, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: October 11, 2016

KCPL KS
Case Name: 2016 Westar Aquisition
Case Number: 16-KCPE-593-ACQ

Response to Figgs Katie Interrogatories - KCC_20160901
Date of Response:

Question:32

Please provide the following information regarding KCPL's response to CURB Data Request No. 52. Provide documentation in EXCEL format supporting Mr. Kemp's analysis and his conclusion that the difference between the merger and non-merger groups' cost changes over the same time periods was "highly significant statistically". Include a listing of the companies in both the merger and non-merger groups, the dates of the 4-year cost comparisons, and all relevant data, including actual costs and statistical results.

RESPONSE: (do not edit or delete this line or anything above this)

In response to CURB Data Request No. 52 regarding the process for determining merger savings and specifically how savings are attributed to the merger instead of other factors, Mr. Kemp discussed an analysis he conducted in 2011 to address the question of whether changes in post-merger costs could be ascribed to industry cost trends not related to mergers. See Q32_CONF_Workpaper 32-1, which provides an Excel spreadsheet with the statistical results of that analysis, a listing of the companies in both the merger and non-merger groups, the dates of the four-year cost comparisons, and details on the statistical significance of differences in mean changes in real costs for peer groups of merger vs. non-merger utilities over the same four-year periods. The actual cost data for the various FERC account groupings for each utility for each year are available from FERC and a number of commercial data bases.

The attached workpaper is **CONFIDENTIAL** as it contains reports, work papers or other documentation related to work produced by internal or external auditors or consultants.

Attachments:

Q32_CONF_Workpaper 32-1_Merger vs Non-Merger Groups.xlsx
Q32_Verification.pdf

Metric	Total Non-Fuel O&M	Gen Non-Fuel O&M	Trans O&M	Dist O&M	Cust Serv	Sales	A&G
Greatest Decrease	-27%	-29%	-39%	-23%	-39%	-97%	-57%
Greatest Increase of Other Transactions	18%	14%	180%	25%	11%	4%	59%
Median of Other Transactions	-1%	-5%	5%	-8%	-17%	-57%	-13%
KCPL-Aquila Estimate	-10%	-4%	-14%	-9%	-24%	0%	-18%

STATISTICAL SIGNIFICANCE OF DIFFERENCES IN MEAN CHANGES IN REAL COSTS - MERGER VS. NON-MERGER UTILITY GROUPS

Function	Mean 4-Year Cost Change[1]		t Statistic	Comment
	Merger Group	Non-Merger Group		
Generation Non-Fuel O&M	-0.64%	8.90%	-2.06	Significant at >90%
Transmission O&M	-27.70%	17.39%	-4.67	Very highly significant
Distribution O&M	3.75%	4.83%	-0.33	Much weaker merger impact
Customer Service	0.04%	24.01%	-3.72	Highly significant
A&G	-5.30%	7.08%	-2.12	Significant at >90%
Total Non-Fuel O&M	-2.42%	9.68%	-1.64	Significant at almost 90%

(1) Constant dollars

- 32 merger transactions vs. 19 utilities without mergers
- Real reduction in cost over a 4-year periods (year before to 3 years after close)
- T test for significance of difference in sample means
- Also samples tested to confirm no significant secular time trends

T-test

Total O&M	v1	v2
Mean change in real costs	-4.21%	7.61%
Variance	5.61%	4.16%
t stat	-1.552	
P(T<=t) one-tail	0.067	
t Critical one-tail	1.708	

v1 = merger group
v2 = non-merger group

regression supports validity of t-test

No-intercept

Regression Statistics		
Multiple R	0.152	0.440
R Square	0.023	0.194
Adjusted R Square	-0.035	0.115
Standard Error	0.231	0.213
Observations	36.000	36.000

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*	*df*	*SS*	*MS*	*F*	*Significance F*
Regression	2.000	0.043	0.021	0.400	0.673	3.000	0.361	0.120	2.647	0.066
Residual	34.000	1.816	0.053			33.000	1.498	0.045		
Total	36.000	1.859				36.000	1.859			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Group Equals (1)	-0.045	0.074	-0.612	0.545	-0.196	-0.121	0.074	-1.636	0.111	-0.272
Trend Year Variable	0.000	0.006	0.058	0.954	-0.012	0.052	0.020	2.557	0.015	0.011
Trend Year Variable Sq.						-0.004	0.002	-2.646	0.012	-0.007

T-test

Generation Non-fuel &M	v1	v2
Mean change in real costs	-0.64%	8.90%
Variance	2.47%	1.35%
t Stat	-2.05804	
P(T<=t) one-tail	0.02434	
t Critical one-tail	1.69913	

v1 = merger group
v2 = non-merger group

highly signfiicant

No-intercept

Regression Statistics		
Multiple R	0.327	0.340
R Square	0.107	0.116
Adjusted R Square	0.051	0.032
Standard Error	0.146	0.147
Observations	36.000	36.000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*	*df*	*SS*	*MS*	*F*	*Significance F*
Regression	2	0.0867	0.0433	2.0328	0.1471	3	0.09408	0.0313601	1.4422049	0.248794726
Residual	34	0.7250	0.0213			33	0.71757	0.0217446		
Total	36	0.8117				36	0.81165			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Group Equals (1)	-0.07644	0.04591	-1.66482	0.10514	-0.16975	-0.08899	0.05112	-1.74087	0.09102	-0.19298
Trend Year Variable	0.00782	0.00390	2.00475	0.05300	-0.00011	0.01570	0.01408	1.11490	0.27295	-0.01295
Trend Year Variable Sq.						-0.00064	0.00110	-0.58312	0.56378	-0.00287

T-test

Transmission O&M	v1	v2
Mean change in real costs	-27.70%	17.39%
Variance	19.76%	0.41%
t Stat	-4.669	
P(T<=t) one-tail	5.31E-05	
t Critical one-tail	1.714	

v1 = merger group
v2 = non-merger group

very highly signfiicant

No-intercept

Regression Statistics		
Multiple R	0.620	0.626
R Square	0.384	0.391
Adjusted R Square	0.334	0.320
Standard Error	0.347	0.350
Observations	34.000	34.000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*	*df*	*SS*	*MS*	*F*	*ignificance F*
Regression	2	2.39942	1.19971	9.977108	0.000451663	3.000	2.445	0.815	6.644	0.001
Residual	32	3.84788	0.12025			31.000	3.802	0.123		
Total	34	6.2473				34.000	6.247			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Group Equals (1)	-0.48450554	0.112901	-4.29142	0.000153	-0.714477059	-0.455	0.124	-3.685	0.001	-0.708
Trend Year Variable	0.0227	0.0093	2.4313	0.0208	0.0037	0.003	0.034	0.080	0.937	-0.067
Trend Year Variable Sq.						0.002	0.003	0.608	0.547	-0.004

T-test

Distribution O&M	v1	v2
Mean change in real costs	3.75%	4.83%
Variance	2.27%	0.17%
t Stat	-0.332	0.000
P(T<=t) one-tail	0.371	0.000
t Critical one-tail	1.697	0.000

v1 = merger group
v2 = non-merger group

directionally consistent but not signfiicant

No-intercept

Regression Statistics		
Multiple R	0.320	0.326
R Square	0.103	0.106
Adjusted R Square	0.048	0.024
Standard Error	0.127	0.128
Observations	37.000	37.000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*	*df*	*SS*	*MS*	*F*	*Significance F*
Regression	2.000	0.043	0.021	0.400	0.673	3	0.06671	0.022236	1.3503996	0.274966355
Residual	34.000	1.816	0.053			34	0.55985	0.016466		
Total	36.000	1.859				37	0.62656			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Group Equals (1)	-0.0036	0.0398	-0.0913	0.9278	-0.0843	-0.01071	0.04421	-0.24219	0.81009	-0.10055
Trend Year Variable	0.0045	0.0034	1.3439	0.1876	-0.0023	0.00907	0.01221	0.74314	0.46250	-0.01574
Trend Year Variable Sq.						-0.00037	0.00095	-0.38719	0.70103	-0.00230

T-test

Customer Acctg and Service	v1	v2
Mean change in real costs	0.04%	24.01%
Variance	8.33%	0.81%
t Stat	-3.722	
P(T<=t) one-tail	0.000	
t Critical one-tail	1.697	

v1 = merger group
v2 = non-merger group

very highly significant

No-intercept

Regression Statistics		
Multiple R	0.455	0.480
R Square	0.207	0.230
Adjusted R Square	0.155	0.153
Standard Error	0.251	0.251
Observations	36.000	36.000

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*	*df*	*SS*	*MS*	*F*	*ignificance*
Regression	2.000	0.559	0.279	4.444	0.020	3.000	0.621	0.207	3.292	0.033
Residual	34.000	2.138	0.063			33.000	2.076	0.063		
Total	36.000	2.697				36.000	2.697			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Group Equals (1)	-0.185	0.080	-2.296	0.028	-0.348	-0.218	0.087	-2.502	0.017	-0.396
Trend Year Variable	0.020	0.007	2.981	0.005	0.006	0.043	0.024	1.791	0.082	-0.006
Trend Year Variable Sq.						-0.002	0.002	-0.996	0.327	-0.006

T-test

Sales Expense	v1	v2
Mean change in real costs	-44.14%	-9.75%
Variance	15.74%	0.63%
t Stat	-4.165	
P(T<=t) one-tail	0.000	
t Critical one-tail	1.701	

v1 = merger group
v2 = non-merger group

very highly significant

No-intercept

Regression Statistics		
Multiple R	0.743	0.758
R Square	0.552	0.575
Adjusted R Square	0.511	0.521
Standard Error	0.336	0.332
Observations	37.000	37.000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*	*df*	*SS*	*MS*	*F*	*ignificance*
Regression	2	4.877901	2.43895	21.5977	8.83252E-07	3.000	5.077	1.692	15.334	0.000
Residual	35	3.952421	0.11293			34.000	3.753	0.110		
Total	37	8.830322				37.000	8.830			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Group Equals (1)	-0.41983094	0.107721	-3.89739	0.00042	-0.638516251	-0.362	0.115	-3.156	0.003	-0.596
Trend Year Variable	-0.002	0.009	-0.256	0.799	-0.020	-0.043	0.031	-1.363	0.182	-0.106
Trend Year Variable Sq.						0.003	0.002	1.345	0.188	-0.002

T-test

A&G	v1	v2
Mean change in real costs	-5.30%	7.08%
Variance	7.56%	0.46%
t Stat	-2.122	
P(T<=t) one-tail	0.021	
t Critical one-tail	1.699	

v1 = merger group
v2 = non-merger group

significant

No-intercept

Regression Statistics		
Multiple R	0.117	0.284
R Square	0.014	0.081
Adjusted R Square	-0.045	-0.003
Standard Error	0.253	0.232
Observations	36.000	37.000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*	*df*	*SS*	*MS*	*F*	*Significance F*
Regression	2.000	0.030	0.015	0.235	0.792	3.000	0.161	0.054	0.995	0.407
Residual	34.000	2.170	0.064			34.000	1.834	0.054		
Total	36.000	2.200				37.000	1.994			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Coefficients*	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
M&A Dummy Variable	-0.043	0.077	-0.553	0.584	-0.200	-0.131	0.080	-1.634	0.112	-0.293
Trend Year (End) Variable	0.005	0.007	0.682	0.500	-0.009	0.011	0.022	0.520	0.606	-0.033
Trend Year Variable Sq.						0.000	0.002	-0.167	0.868	-0.004

Merger Group

Acquiror (or Larger Entity)	Acquiree	Closing Date	Before Year Form 1&2	After Year Form 1&2
Ameren Corporation	CILCORP, Inc.	02/05/03	2002	2006
Ameren Corporation	Illinois Power Company	10/02/04	2003	2007
American Electric Power Company, Inc. (AE	Central and South West Corporation	06/15/00	1999	2003
Brooklyn Union Gas	Long Island Lighting Company	05/29/98	1997	2000
Carolina Power and Light Company (CP&L)	Florida Progress Corporation	11/30/00	1999	2003
Unicom (Commonwealth Edison)	PECO Energy	10/23/00	1999	2003
Consolidated Edison Company of New York	Orange and Rockland Utilities, Inc.	07/01/99	1998	2002
Delmarva Power & Light Company	Atlantic Energy Inc.	03/01/99	1998	2002
Dominion Resources, Inc.	Consolidated Natural Gas Co.	01/28/00	1999	2003
Duke Energy	Cinergy	04/30/06	2005	2009
Energy East Corporation	Central Maine Power Company	09/01/00	1999	2003
FirstEnergy Corporation	GPU, Inc.	11/07/01	2000	2004
Indiana Energy Inc.	SIGCORP, Inc.	03/31/00	1999	2002
LG&E Energy LLC	Kentucky Utilities Company (KU)	05/04/98	1997	2001
Midamerican Energy	PacifiCorp	03/21/06	2005	2009
Nevada Power Company	Sierra Pacific Power Company	07/28/99	1998	2002
Northern States Power Company	New Century Energies, Inc.	08/17/00	1999	2003
Ohio Edison Company	Centerior Energy	11/07/97	1996	2000
Pacific Enterprises	Enova Corporation	06/28/98	1997	2000
PNM Resources Inc.	TNP Enterprises, Inc.	06/06/05	2004	2008
Potomac Electric Power Company	Conectiv Energy, Inc.	08/01/02	2001	2005
Puget Sound Power & Light Company	Washington Energy Co	02/10/97	1996	1999
Union Electric Company	CIPSCO Inc.	12/31/97	1997	2001
Laclede Gas Company	Fidellity Natural Gas, Inc.	02/28/06	2005	2009
WPS Resources	Peoples Energy Corp.	02/21/07	2006	2010
National Grid	KeySpan Corp	08/24/07	2006	2010
MDU Resources	Cascade Natural Gas	07/02/07	2006	2010
UGI Corporation	PG Energy	08/24/06	2005	2009
Great Plains (Kansas City Power & Light)	Aquila Inc. (MO)	07/14/08	2007	2010
Chesapeake Utilities Corp	Florida Public Utilities Corp	10/28/09	2008	2010
MDU Resources	Intermountain Gas	10/1/2008	2007	2010

Notes: 2010 was latest year of FERC data available at the time of this analysis
FERC data for third year after transaction close not available for some transactions; second year after close used instead for those transactions

Non-Merger Group (not involved at all in a tuility-utility merger over the 1996-2010 study period, or most recent merger was at least the five years prior to the pair of years considered)

CenterPoint Energy, Inc.
CH Energy Group, Inc.
Cleco Corporation
CMS Energy Corporation
Duquesne Light Holdings, Inc.
Energy Future Holdings Corp.
Entergy
Hawaiian Electric Industries, Inc.
IDACORP
MGE Energy, Inc.
Otter Tail Corporation
Pinnacle West Capital Corporation
Public Service Enterprise Group Incorporated
Puget Sound Energy, Inc.
TECO Energy, Inc.
Vectren
Westar Energy
DPL Inc.
Pacific Gas and Electric Company
Southern Company

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to KCC Data Request# 32, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: September 15, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20161107
Date of Response:

Question:3-4

In reference to the response BPU 2-36, please:

1. Provide Mr. Kemp's definition of "extreme values" as he uses that term in response to BPU-2-36(1).

2. Identify all of the "extreme values" contained in the EP database which Mr. Kemp excluded from his merger savings analysis. For each such "extreme value" he identified and excluded, please provide the rationale for the exclusion, including an explanation for how Mr. Kemp determined the values he excluded were "extreme."

3. In his response to BPU-2-36(2), Mr. Kemp states "The difficulties of comparing estimated merger benefits across a heterogeneous population of merger transactions is precisely the reason why an ex-post statistical analysis using consistent sets of FERC data was selected as a more valid approach." Confirm that when Mr. Kemp references "statistical analysis," he is referring to the "Change in Real Costs" page on Workpaper CURB-50-1. If the answer is "no," please describe the "statistical analysis" Mr. Kemp performed and provide that analysis in its entirety, including all supporting data and workpapers.

RESPONSE: (do not edit or delete this line or anything above this)

1. As explained in response to BPU Data Request No. 2-36 and pages 34-35 of Mr. Kemp's testimony, "extreme values" in this context mean values that were well outside of the range that could plausibly be merger-related effects. In most cases, these extreme values could be linked to structural or regulatory changes.

2. The cells with red shading in columns D through J in the work paper provided in the GPE's response to BPU Data Request No. 3-1 are the extreme values that were excluded from the comparison of changes in real costs. (Note: The values for the Sales function were not used in Mr. Kemp's calculation of realized merger savings, as they are de minimis for utilities.) The rationales for exclusion for the specific cells are as follows:

Excluded Cell	Rationale
E10	Generation divestiture
E11	Generation divestiture
J11	Well outside of range; not merger related
E16	Generation divestiture
G17	Well outside of range; not merger related
J19	Well outside of range; not merger related

Excluded Cell	Rationale
E22	Generation divestiture
F22	ISO/RTO start-up
G26	Well outside of range; not merger related
E30	Generation divestiture
E32	Generation divestiture
J32	Well outside of range; not merger related

3. Yes. Confirmed.

Attachment: Q3-4_Verification.pdf

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to BPU Data Request# 3-4, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: November 14, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20161107
Date of Response:

Question:3-1

In reference to the response BPU 2-4 and Workpaper CURB-50-1_Functional Savings by Merger Transaction.pdf, please:

1. Provide a working copy of the spreadsheet that was converted into a pdf for Workpaper CURB-50-1.

2. Confirm that the EP Database referenced in Mr. Kemp's testimony is Workpaper CURB -50-1. If the EP Database contains other information not contained in Workpaper CURB-50-1, please identify all data excluded and provide that data.

3. On the column headings of CURB-50-1, please confirm that "NF" means "Non-Fuel." If "NF" means something else, please identify.

4. Provide Mr. Kemp's definition of "merger savings."

RESPONSE: (do not edit or delete this line or anything above this)

1. See the attached "Workpaper CURB 50-1_Updated for BPU 3-1."

   Please note that Workpaper CURB-50-1 is **CONFIDENTIAL** as it contains (1) Reports, work papers or other documentation related to work produced by internal or external auditors or consultants; (2) Strategies employed, to be employed, or under consideration; and (3) Information concerning trade secrets, as well as private, technical, financial and business information.

2. The workpaper provided in part 1 above contains the data base of percentage changes in real costs for FERC account groups, which Mr. Kemp relied upon for Schedule WJK-5. The actual cost data for the various individual FERC accounts for each utility for each year in the comparable transactions, from which the percentage cost changes were calculated, are available from FERC and a number of commercial data bases.

3. Yes. NF means non-fuel.

4, In the context of Schedule WJK-5, "merger savings" are the difference between inflation-adjusted costs three years after the year of transaction close vs. costs in the year before close. See the footnote on page 35 of Mr. Kemp's testimony.

Attachments:

Workpaper CURB 50-1_Updated for BPU 3-1_CONF.xlsx
QKEPCo 3-1_Verification.pdf

Workpaper for Schedule WJK-5

Transaction

Change in Real Costs (Close + 3 years vs. Close - 1 year)

Deal Year	Buyer Name/ Target Name	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	A&G O&M	Cust Svc
1997	Ohio Edison Company/ Centerior Energy	-2.7%	1.7%	62.1%	-12.0%	-13.0%	-26%
1997	Puget Sound Power & Light Company/ Washington Energy Co	3.1%	-6.9%	0.0%	15.5%	-11.5%	8%
1998	Brooklyn Union Gas/ Long Island Lighting Company	22.6%	0.0%		-6.4%	42.9%	0%
1998	LG&E Energy LLC/ Kentucky Utilities Company (KU)	5.6%	-12.5%	20.2%	-22.7%	32.7%	-38%
1998	Pacific Enterprises/ Enova Corporation	-11.3%	-40.1%	47.1%	-1.0%	-12.5%	-4%
1998	Union Electric Company/ CIPSCO Inc.	6.8%	-17.1%	-8.6%	23.5%	6.1%	3%
1999	Consolidated Edison Company of New York/ Orange and Rockland Utilities, Inc.	-5.1%	-86.9%	-9.2%	3.4%	-56.8%	-10%
1999	Delmarva Power & Light Company/ Atlantic Energy Inc.	-0.1%	-108.4%	19.3%	3.8%	-47.8%	88%
1999	Nevada Power Company/ Sierra Pacific Power Company	4.6%	0.0%	73.1%	-1.6%	3.9%	0%
2000	SCANA Corporation/ Public Service Company of North Carolina, Incorporated	15%	8%	10%	-18%	43%	9%
2000	American Electric Power Company, Inc. (AEP)/ Central and South West Corp.	-10.7%	4.9%	-13.6%	6.3%	-13.6%	-20%
2000	Carolina Power and Light Company (CP&L)/ Florida Progress Corporation	8.9%	11.9%	3.3%	-9.4%	59.0%	-30%
2000	Unicom (Commonwealth Edison)/ PECO Energy	-27.2%	-99.9%	-32.9%	-5.9%	-29.0%	-27%
2000	Dominion Resources, Inc./ Consolidated Natural Gas Co.	-1.7%	-34.5%	1.2%	49.3%	-10.5%	-10%
2000	Energy East Corporation/ Central Maine Power Company	-11.7%	-86.0%	4.9%	14.8%	-22.7%	-16%
2000	Indiana Energy Inc./ SIGCORP, Inc.	-23.2%	-5.4%	3.0%	-3.7%	-20.9%	282%
2000	Northern States Power Company / New Century Energies, Inc.	15.5%	14.4%	52.9%	-14.9%	40.7%	7%
2001	AES Corporation/ IPALCO Enterprises, Inc.	-32%	-10%	32%	-3%	-55%	-20%
2001	FirstEnergy Corporation/ GPU, Inc.	18.3%	-77.8%	180.3%	-13.4%	18.1%	0%
2002	Potomac Electric Power Company/ Conectiv Energy, Inc.	2.4%	0.0%	7.8%	-10.1%	27.5%	-14%
2003	Ameren Corporation/ CILCORP, Inc.	-12.4%	-28.7%	-26.4%	11.0%	-23.0%	-14%
2004	Northeast Utilities/ Connecticut Valley Electric Co Inc.	27%	3%	77%	12%	24%	18%
2004	Ameren Corporation/ Illinois Power Company	7.4%	-8.9%	-19.9%	30.9%	-12.0%	0%
2005	PNM Resources Inc./ TNP Enterprises, Inc.	-6.2%	25.2%	9.4%	0.0%	-9.5%	-28%
2006	Duke Energy/ Cinergy	-33.0%	-8.9%	-44.1%	-19.3%	-36.6%	-33%
2006	Midamerican Energy/ PacifiCorp	-1.3%	13.8%	55.9%	-2.3%	-30.2%	8%
2006	UGI Corporation/ PG Energy	22.5%	-79.0%	-6.3%	3.5%	7.1%	-10%
2007	WPS Resources/ Peoples Energy Corp.	20.4%	4.6%	49.7%	23.7%	-3.2%	27%
2007	National Grid/ KeySpan Corp	31.9%	-76.2%	31.9%	13.1%	34.9%	61%
2007	MDU Resources/ Cascade Natural Gas	-7.5%	-2.5%	12.1%	2.0%	-13.6%	-7%
2008	Great Plains (Kansas City Power & Light)/ Aquila Inc. (MO)	-9.3%	13.0%	-18.1%	-7.0%	-14.3%	39%
2008	MDU Resources/ Intermountain Gas	-2.6%	5.7%	21.1%	0.3%	-4.2%	-18%
2011	AES Corporation/ DPL Inc.	-1%	-12%	11%	2%	-6%	35%
2011	FirstEnergy Corp./ Allegheny Energy, Inc.	20%	9%	21%	2%	53%	12%
2012	Northeast Utilities/ NSTAR	-3%	-30%	13%	-13%	-11%	13%
2012	Exelon Corporation/ Constellation Energy Group, Inc.	1%	0%	-11%	2%	4%	7%

Outliers or Irrelevant

Table not used; pre-scrubbing

NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	A&G O&M	Cust Svc	
-33%	-108%	-44%	-23%	-57%	-38%	IN
-8%	-31%	-7%	-8%	-16%	-17%	½)
0%	-6%	10%	0%	-10%	0%	ı)
10%	5%	32%	7%	20%	9%	½)
32%	25%	180%	49%	59%	282%	‹)
18%	36%	39%	15%	36%	26%	Inr
-35%	-85%	-67%	-30%	-69%	-56%	ɔr
38%	58%	91%	30%	73%	48%	ɔr

Change in Real Costs (close + 3 yrs vs. close - 1 yr)

NF Electric O&M		NF Gen O&M		Trans O&M		Distrib O&M		Sales		Cust Svc		A&G O&M		Electric O&M	
-2.7%		1.7%		62.1%		-12.0%		0.0%		-26.2%		-13.0%		-5.3%	
3.1%		-6.9%		0.0%		15.5%	N			8.1%		-11.5%		6.4%	
22.6%		0.0%		0.0%		-6.4%	N			0.3%		42.9%		0.0%	
5.6%		-12.5%		20.2%		-22.7%		-97.1%		-38.0%		32.7%		17.8%	
-11.3%		-40.1%		47.1%		-1.0%		-98.9%		-3.7%		-12.5%	N		
6.8%		-17.1%		-8.6%		23.5%		-52.5%		3.2%		6.1%		15.1%	
-5.1%	N			-9.2%		3.4%		-17.2%		-10.3%		-56.8%		3.9%	
-0.1%	N			19.3%		3.8%	N		N			-47.8%		-19.9%	
4.6%		0.0%		73.1%		-1.6%		-62.6%		0.2%		3.9%	N		
15.1%		7.7%		10.1%		-17.9%	N			8.5%		43.2%		8.9%	
-10.7%		4.9%		-13.6%		6.3%		-96.7%		-19.8%		-13.6%		5.0%	
8.9%		11.9%		3.3%		-9.4%		-37.8%		-30.1%		59.0%		18.2%	
-27.2%	N			-32.9%		-5.9%		-84.9%		-26.7%		-29.0%		-20.6%	
-1.7%		-34.5%		1.2%	N			-65.6%		-10.0%		-10.5%		5.4%	
-11.7%	N			4.9%		14.8%		-31.6%		-16.1%		-22.7%		-26.1%	
-23.2%		-5.4%		3.0%		-3.7%		-79.8%	N			-20.9%	N		
15.5%		14.4%		52.9%		-14.9%		-56.3%		6.9%		40.7%		12.4%	
-32.2%		-9.6%		32.1%		-2.9%		-100.0%		-19.7%		-54.8%		-21.0%	
18.3%	N		N			-13.4%		-92.4%		-0.4%		18.1%		11.2%	
2.4%		0.0%		7.8%		-10.1%		4.2%		-14.5%		27.5%		-3.9%	
-12.4%		-28.7%		-26.4%		11.0%		-57.6%		-14.5%		-23.0%		-1.6%	
26.6%		2.8%		77.4%		11.8%		-42.0%		18.0%		23.9%		21.4%	
7.4%		-8.9%		-19.9%	N			-50.6%		-0.5%		-12.0%		6.9%	
-6.2%		25.2%		9.4%		0.0%		-11.3%		-27.8%		-9.5%		-7.9%	
-33.0%		-8.9%		-44.1%		-19.3%		-94.1%		-33.2%		-36.6%	N		
-1.3%		13.8%		55.9%		-2.3%	N			8.0%		-30.2%		7.5%	
22.5%	N			-6.3%		3.5%		-25.5%		-10.1%		7.1%	N		
20.4%		4.6%		49.7%		23.7%		-100.0%		26.5%		-3.2%		1.6%	
31.9%	N			31.9%		13.1%		-53.8%	N			34.9%		-19.5%	
-7.5%		-2.5%		12.1%		2.0%		-63.5%		-6.9%		-13.6%		-10.9%	
-9.3%		13.0%		-18.1%		-7.0%		-30.0%		39.4%		-14.3%		-13.8%	
-2.6%		5.7%		21.1%		0.3%		-55.3%		-18.5%		-4.2%		-9.2%	
-0.6%		-11.9%		10.6%		2.3%		0.0%		34.6%		-6.4%		9.6%	
20.4%		9.2%		20.9%		2.4%		-56.2%		11.9%		52.9%		-34.3%	
-2.8%		-29.9%		13.3%		-13.5%		-58.2%		13.2%		-11.0%		0.8%	
0.7%		0.0%		-11.1%		1.5%		-42.8%		7.3%		4.5%		-30.3%	

[not used]

("N" = outlier or structurally irrelevant)

Quartile Breaks

NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	Cust Svc	A&G O&M	Electric O&M	
-33.0%	-40.1%	-44.1%	-22.7%	-100.0%	-38.0%	-56.8%	-34.3%	
-7.9%	-9.6%	-7.5%	-8.8%	-82.4%	-18.5%	-16.0%	-12.3%	
-0.3%	0.0%	9.4%	-0.5%	-56.2%	-3.7%	-10.0%	0.8%	
10.4%	5.7%	26.5%	3.7%	-34.7%	8.0%	19.6%	8.2%	
31.9%	25.2%	77.4%	23.7%	4.2%	39.4%	59.0%	21.4%	
18.3%	15.4%	33.9%	12.6%	47.7%	26.4%	35.5%	20.5%	
-35.4%	-32.7%	-58.4%	-27.7%	-153.9%	-58.1%	-69.2%	-43.1%	
37.9%	28.8%	77.4%	22.6%	36.8%	47.6%	72.8%	39.0%	

Color Block Breaks for Stacked Bar Chart (reverse order of bars)

	A&G	Cust Svc	Dist O&M	Trans O&M	Gen NF O&M	Total NFOM
Best	-10%	-4%	-8%	-7%	-10%	-8%
75th Percentile	-6%	-14%	-15%	-37%	-30%	-25%
Median	-41%	-20%	0%	10%	0%	0%
25th Percentile	20%	8%	5%	22%	6%	10%
Worst	39%	31%	20%	45%	19%	22%

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to BPU Data Request# 3-1, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: November 14, 2016

KCPL KS
Case Name: 2016 Westar Acquisition
Case Number: 16-KCPE-593-ACQ

Response to Bond Ashley Interrogatories - BPU_20161107
Date of Response: 12/14/2016

Question:3-1A

Amended:

In reference to the response BPU 2-4 and Workpaper CURB-50-1_Functional Savings by Merger Transaction.pdf, please:

1. Provide a working copy of the spreadsheet that was converted into a pdf for Workpaper CURB-50-1.

2. Confirm that the EP Database referenced in Mr. Kemp's testimony is Workpaper CURB -50-1. If the EP Database contains other information not contained in Workpaper CURB-50-1, please identify all data excluded and provide that data.

3. On the column headings of CURB-50-1, please confirm that "NF" means "Non-Fuel." If "NF" means something else, please identify.

4. Provide Mr. Kemp's definition of "merger savings."

Number of Attachments:

Response:

1. **AMENDED:** See the attached "Workpaper CURB 50-1_Updated for BPU 3-1 v2." This Excel spreadsheet contains the values and formulas for all pages of the PDF workpaper provided with the response to CURB 50. Please note that some of the values a few of the quartile break points have changed slightly in this updated spreadsheet, due to deletion of zero values in some cells in the percentage cost changes tables, to show them more appropriately as blank cells. The zero values distorted the results of the quartile formulas.

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Please note that the data presented in Workpaper CURB-50-1 are considered highly confidential and proprietary by Mr. Kemp and his employer, and should not be distributed to third parties.

2. The workpaper provided in part 1 above contains the data base of percentage changes in real costs for FERC account groups, which Mr. Kemp relied upon for Schedule WJK-5. The actual cost data for the various individual FERC accounts for each utility for each year in the comparable transactions, from which the percentage cost changes were calculated, are available from FERC and a number of commercial data bases.

3. Yes. NF means non-fuel.

4, In the context of Schedule WJK-5, "merger savings" are the difference between inflation-adjusted costs three years after the year of transaction close vs. costs in the year before close. See the footnote on page 35 of Mr. Kemp's testimony.

Attachments:

Workpaper CURB 50-1_Updated for BPU 3-1_CONF.xlsx
QKEPCo 3-1_Verification.pdf

Percentage Cost Changes and Reported Costs by FERC Account Group

Calculated from FERC costs

Trans-action Number	Deal Year	Buyer Name/ Target Name	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	A&G O&M	Cust Svc	Electric O&M	Note
1	1997	Ohio Edison Company/ Centerior Energy	-2.7%	1.7%	62.1%	-12.0%	392.3%	-13.0%	-26.2%	-5.3%	
2	1997	Puget Sound Power & Light Company/ Washington Energy Co	3.1%	-6.9%		15.5%	423.4%	-11.5%	8.1%	6.4%	
3	1998	Brooklyn Union Gas/ Long Island Lighting Company	22.6%		1185.6%	-6.4%	140.9%	42.9%	0.3%		
4	1998	LG&E Energy LLC/ Kentucky Utilities Company (KU)	5.6%	-12.5%	20.2%	-22.7%	-97.1%	32.7%	-38.0%	46.7%	
5	1998	Pacific Enterprises/ Enova Corporation	-11.3%	-40.1%	47.1%	-1.0%	-98.9%	-12.5%	-3.7%		
6	1998	Union Electric Company/ CIPSCO Inc.	6.8%	-17.1%	-8.6%	23.5%	-52.5%	6.1%	3.2%	29.7%	
7	1999	Consolidated Edison Company of New York/ Orange and Rockland Utilities, Inc.	-5.1%		-9.2%	3.4%	-17.1%	-56.8%	-10.3%	24.0%	
8	1999	Delmarva Power & Light Company/ Atlantic Energy Inc.	-0.1%		19.3%	3.8%		-47.8%	87.9%	-11.4%	
9	1999	Nevada Power Company/ Sierra Pacific Power Company	4.6%	541.4%	73.1%	-1.6%	-62.6%	3.9%	0.2%	165.2%	
10	2000	SCANA Corporation/ Public Service Company of North Carolina, Incorporated	15.1%	7.7%	10.1%	-17.9%	79.3%	43.2%	8.5%	8.9%	
11	2000	American Electric Power Company, Inc. (AEP)/ Central and South West Corporation	-10.7%	4.9%	-13.6%	6.3%	-96.7%	-13.6%	-19.8%	5.0%	
12	2000	Carolina Power and Light Company (CP&L)/ Florida Progress Corporation	8.9%	11.9%	3.3%	-9.4%	-37.8%	59.0%	-30.1%	18.2%	
13	2000	Unicom (Commonwealth Edison)/ PECO Energy	-27.2%		-32.9%	-5.9%	-84.9%	-29.0%	-26.7%	-13.4%	
14	2000	Dominion Resources, Inc./ Consolidated Natural Gas Co.	-1.7%	-34.5%	1.2%	49.3%	-65.6%	-10.5%	-10.0%	44.2%	
15	2000	Energy East Corporation/ Central Maine Power Company	-11.7%		4.9%	14.8%	-31.6%	-22.7%	-16.1%	-11.8%	
16	2000	Indiana Energy Inc./ SIGCORP, Inc.	-23.2%	-5.4%	3.0%	-3.7%	-79.8%	-20.9%	282.4%	142.8%	
17	2000	Northern States Power Company / New Century Energies, Inc.	15.5%	14.4%	52.9%	-14.9%	-56.3%	40.7%	6.9%	31.9%	
18	2001	AES Corporation/ IPALCO Enterprises, Inc.	-32.2%	-9.6%	32.1%	-2.9%	-100.0%	-54.8%	-19.7%	-21.0%	
19	2001	FirstEnergy Corporation/ GPU, Inc.	18.3%		180.3%	-13.4%	-92.4%	18.1%	-0.4%	11.2%	
20	2002	Potomac Electric Power Company/ Conectiv Energy, Inc.	2.4%	-566.6%	7.8%	-10.1%	4.2%	27.5%	-14.5%	-3.9%	
21	2003	Ameren Corporation/ CILCORP, Inc.	-12.4%	-28.7%	-26.4%	11.0%	-57.6%	-23.0%	-14.5%	21.6%	
22	2004	Northeast Utilities/ Connecticut Valley Electric Co Inc.	26.6%	2.8%	77.4%	11.8%	-42.1%	23.9%	18.0%	21.4%	
23	2004	Ameren Corporation/ Illinois Power Company	7.4%	-8.9%	-19.9%	30.9%	-50.6%	-12.0%	-0.5%	37.7%	
24	2005	PNM Resources Inc./ TNP Enterprises, Inc.	-6.2%	25.2%	9.4%	0.0%	-11.3%	-9.5%	-27.8%	28.3%	
25	2006	Duke Energy/ Cinergy	-33.0%	-8.9%	-44.1%	-19.3%	-94.1%	-36.6%	-33.2%	-76.4%	
26	2006	Midamerican Energy/ PacifiCorp	-1.3%	13.8%	55.9%	-2.3%	65.7%	-30.2%	8.0%	7.5%	
27	2006	UGI Corporation/ PG Energy	22.5%		-6.3%	3.5%	-25.4%	7.1%	-10.1%	53.4%	
28	2007	WPS Resources/ Peoples Energy Corp.	20.4%	4.6%	49.7%	23.7%	-100.0%	-3.2%	26.5%	153.4%	
29	2007	National Grid/ KeySpan Corp	31.9%		31.9%	13.1%	-53.8%	34.9%	60.8%	57.1%	
30	2007	MDU Resources/ Cascade Natural Gas	-7.5%	-2.5%	12.1%	2.0%	-63.5%	-13.6%	-6.9%	166.7%	
31	2008	Great Plains (Kansas City Power & Light)/ Aquila Inc. (MO)	-9.3%	13.0%	-18.1%	-7.0%	-30.0%	-14.3%	39.4%	-13.8%	
32	2008	MDU Resources/ Intermountain Gas	-2.7%	5.7%	21.1%	0.3%	-55.2%	-4.2%	-18.5%	-9.2%	
33	2011	AES Corporation/ DPL Inc.	-0.6%	-11.9%	10.6%	2.3%		-6.4%	34.6%	9.6%	
34	2011	FirstEnergy Corp./ Allegheny Energy, Inc.	20.4%	9.2%	20.9%	2.4%	-56.2%	52.9%	11.9%	-34.3%	
35	2012	Northeast Utilities/ NSTAR	-2.8%	-29.9%	13.3%	-13.5%	-58.2%	-11.0%	13.2%	0.8%	
36	2012	Exelon Corporation/ Constellation Energy Group, Inc.	0.7%		-11.1%	1.5%	-42.8%	4.5%	7.3%	-30.3%	
		Outliers					(column not used)			(column not used)	

(blank cells indicate division by zero)

Percentage Cost Changes Excluding Outliers

Trans-action Number	Deal Year	Buyer Name/ Target Name	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	A&G O&M	Cust Svc	Electric O&M
1	1997	Ohio Edison Company/ Centerior Energy	-2.7%	1.7%	62.1%	-12.0%	N	-13.0%	-26.2%	-5.3%
2	1997	Puget Sound Power & Light Company/ Washington Energy Co	3.1%	-6.9%		15.5%	N	-11.5%	8.1%	6.4%
3	1998	Brooklyn Union Gas/ Long Island Lighting Company	22.6%		N	-6.4%	N	42.9%	0.3%	
4	1998	LG&E Energy LLC/ Kentucky Utilities Company (KU)	5.6%	-12.5%	20.2%	-22.7%	-97.1%	32.7%	-38.0%	46.7%
5	1998	Pacific Enterprises/ Enova Corporation	-11.3%	-40.1%	47.1%	-1.0%	-98.9%	-12.5%	-3.7%	
6	1998	Union Electric Company/ CIPSCO Inc.	6.8%	-17.1%	-8.6%	23.5%	-52.5%	6.1%	3.2%	29.7%
7	1999	Consolidated Edison Company of New York/ Orange and Rockland Utilities, Inc.	-5.1%		-9.2%	3.4%	-17.1%	-56.8%	-10.3%	24.0%
8	1999	Delmarva Power & Light Company/ Atlantic Energy Inc.	-0.1%		19.3%	3.8%		-47.8%	N	-11.4%
9	1999	Nevada Power Company/ Sierra Pacific Power Company	4.6%	N	73.1%	-1.6%	-62.6%	3.9%	0.2%	N
10	2000	SCANA Corporation/ Public Service Company of North Carolina, Incorporated	15.1%	7.7%	10.1%	-17.9%	N	43.2%	8.5%	8.9%
11	2000	American Electric Power Company, Inc. (AEP)/ Central and South West Corporation	-10.7%	4.9%	-13.6%	6.3%	-96.7%	-13.6%	-19.8%	5.0%
12	2000	Carolina Power and Light Company (CP&L)/ Florida Progress Corporation	8.9%	11.9%	3.3%	-9.4%	-37.8%	59.0%	-30.1%	18.2%
13	2000	Unicom (Commonwealth Edison)/ PECO Energy	-27.2%		-32.9%	-5.9%	-84.9%	-29.0%	-26.7%	-13.4%
14	2000	Dominion Resources, Inc./ Consolidated Natural Gas Co.	-1.7%	-34.5%	1.2%	N	-65.6%	-10.5%	-10.0%	44.2%
15	2000	Energy East Corporation/ Central Maine Power Company	-11.7%	N	4.9%	14.8%	-31.6%	-22.7%	-16.1%	-11.8%
16	2000	Indiana Energy Inc./ SIGCORP, Inc.	-23.2%	-5.4%	3.0%	-3.7%	-79.8%	-20.9%	N	N
17	2000	Northern States Power Company / New Century Energies, Inc.	15.5%	14.4%	52.9%	-14.9%	-56.3%	40.7%	6.9%	31.9%
18	2001	AES Corporation/ IPALCO Enterprises, Inc.	-32.2%	-9.6%	32.1%	-2.9%	N	-54.8%	-19.7%	-21.0%
19	2001	FirstEnergy Corporation/ GPU, Inc.	18.3%		N	-13.4%	-92.4%	18.1%	-0.4%	11.2%
20	2002	Potomac Electric Power Company/ Conectiv Energy, Inc.	2.4%	N	7.8%	-10.1%	4.2%	27.5%	-14.5%	-3.9%
21	2003	Ameren Corporation/ CILCORP, Inc.	-12.4%	-28.7%	-26.4%	11.0%	-57.6%	-23.0%	-14.5%	21.6%
22	2004	Northeast Utilities/ Connecticut Valley Electric Co Inc.	26.6%	2.8%	77.4%	11.8%	-42.1%	23.9%	18.0%	21.4%
23	2004	Ameren Corporation/ Illinois Power Company	7.4%	-8.9%	-19.9%	N	-50.6%	-12.0%	-0.5%	37.7%
24	2005	PNM Resources Inc./ TNP Enterprises, Inc.	-6.2%	25.2%	9.4%	0.0%	-11.3%	-9.5%	-27.8%	28.3%
25	2006	Duke Energy/ Cinergy	-33.0%	-8.9%	-44.1%	-19.3%	-94.1%	-36.6%	-33.2%	N
26	2006	Midamerican Energy/ PacifiCorp	-1.3%	13.8%	55.9%	-2.3%	N	-30.2%	8.0%	7.5%
27	2006	UGI Corporation/ PG Energy	22.5%		-6.3%	3.5%	-25.4%	7.1%	-10.1%	53.4%
28	2007	WPS Resources/ Peoples Energy Corp.	20.4%	4.6%	49.7%	23.7%	N	-3.2%	26.5%	N
29	2007	National Grid/ KeySpan Corp	31.9%		31.9%	13.1%	-53.8%	34.9%	N	57.1%
30	2007	MDU Resources/ Cascade Natural Gas	-7.5%	-2.5%	12.1%	2.0%	-63.5%	-13.6%	-6.9%	N
31	2008	Great Plains (Kansas City Power & Light)/ Aquila Inc. (MO)	-9.3%	13.0%	-18.1%	-7.0%	-30.0%	-14.3%	39.4%	-13.8%
32	2008	MDU Resources/ Intermountain Gas	-2.7%	5.7%	21.1%	0.3%	-55.2%	-4.2%	-18.5%	-9.2%
33	2011	AES Corporation/ DPL Inc.	-0.6%	-11.9%	10.6%	2.3%		-6.4%	34.6%	9.6%
34	2011	FirstEnergy Corp./ Allegheny Energy, Inc.	20.4%	9.2%	20.9%	2.4%	-56.2%	52.9%	11.9%	-34.3%
35	2012	Northeast Utilities/ NSTAR	-2.8%	-29.9%	13.3%	-13.5%	-58.2%	-11.0%	13.2%	0.8%
36	2012	Exelon Corporation/ Constellation Energy Group, Inc.	0.7%		-11.1%	1.5%	-42.8%	4.5%	7.3%	-30.3%
							(column not used)			(column not used)

Reported Costs Close - 1 yrs

Trans-action Number	Deal Year	Buyer Name/ Target Name	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	A&G O&M	Cust Svc	Electric O&M
1	1997	Ohio Edison Company/ Centerior Energy	1,920,068	1,099,079	58,544	220,591	12,008	361,457	118,438	3,342,208
2	1997	Puget Sound Power & Light Company/ Washington Energy Co	412,593	141,855	-	74,706	987	143,023	47,340	1,535,356
3	1998	Brooklyn Union Gas/ Long Island Lighting Company	459,067	-	758	157,556	10,223	176,375	12,529	-
4	1998	LG&E Energy LLC/ Kentucky Utilities Company (KU)	474,619	185,551	19,549	92,255	11,052	150,031	46,656	1,049,359
5	1998	Pacific Enterprises/ Enova Corporation	1,641,544	174,040	96,544	338,492	357	678,482	184,272	-
6	1998	Union Electric Company/ CIPSCO Inc.	1,028,281	444,308	36,476	175,775	7,046	381,814	77,010	2,112,305
7	1999	Consolidated Edison Company of New York/ Orange and Rockland Utilities, Inc.	1,313,444	-	211,853	556,744	2,088	590,739	302,105	4,525,098
8	1999	Delmarva Power & Light Company/ Atlantic Energy Inc.	374,588	-	18,776	94,936	-	238,365	46,311	2,160,043
9	1999	Nevada Power Company/ Sierra Pacific Power Company	680,285	63,424	15,903	53,006	1,023	170,576	47,255	1,287,114
10	2000	SCANA Corporation/ Public Service Company of North Carolina, Incorporated	280,969	123,428	9,030	33,933	2,008	77,373	35,197	709,018
11	2000	American Electric Power Company, Inc. (AEP)/ Central and South West Corporation	3,434,009	1,345,593	247,495	452,792	19,136	817,955	315,803	8,514,905
12	2000	Carolina Power and Light Company (CP&L)/ Florida Progress Corporation	1,568,551	622,071	94,094	206,181	29,554	325,780	273,537	4,180,805
13	2000	Unicom (Commonwealth Edison)/ PECO Energy	2,391,265	-	126,982	604,125	56,383	1,165,621	392,659	8,489,962
14	2000	Dominion Resources, Inc./ Consolidated Natural Gas Co.	1,355,419	418,487	67,796	283,369	6,167	504,492	112,135	3,550,712
15	2000	Energy East Corporation/ Central Maine Power Company	672,858	-	81,228	195,398	9,871	187,951	134,967	2,407,457
16	2000	Indiana Energy Inc./ SIGCORP, Inc.	284,008	56,382	2,432	47,123	5,338	107,658	5,006	228,312
17	2000	Northern States Power Company / New Century Energies, Inc.	1,964,813	836,181	166,694	307,688	24,949	379,302	225,748	4,965,678
18	2001	AES Corporation/ IPALCO Enterprises, Inc.	287,546	81,502	5,492	31,212	2,233	143,889	23,217	486,314
19	2001	FirstEnergy Corporation/ GPU, Inc.	1,631,103	-	159,487	445,925	60,416	497,311	265,003	6,689,645
20	2002	Potomac Electric Power Company/ Conectiv Energy, Inc.	738,229	(39,307)	41,109	175,504	6,630	181,286	154,541	3,105,031
21	2003	Ameren Corporation/ CILCORP, Inc.	1,386,627	486,670	71,474	261,088	5,454	519,822	109,203	2,830,333
22	2004	Northeast Utilities/ Connecticut Valley Electric Co Inc.	742,311	66,157	112,652	151,249	582	219,735	191,937	3,019,591
23	2004	Ameren Corporation/ Illinois Power Company	1,446,123	404,643	112,389	333,623	4,935	578,891	131,699	3,709,703
24	2005	PNM Resources Inc./ TNP Enterprises, Inc.	597,583	167,430	89,656	69,065	6,178	170,753	40,010	1,191,006
25	2006	Duke Energy/ Cinergy	4,453,377	1,419,720	219,735	462,436	13,213	1,549,172	273,842	27,793,909
26	2006	Midamerican Energy/ PacifiCorp	1,682,498	563,043	146,781	315,809	3,977	363,777	203,518	3,470,861
27	2006	UGI Corporation/ PG Energy	142,200	-	6,428	41,718	2,052	65,652	28,585	72,080
28	2007	WPS Resources/ Peoples Energy Corp.	752,084	74,106	80,932	160,748	1,535	324,461	107,566	977,276
29	2007	National Grid/ KeySpan Corp	2,448,018	-	433,516	685,264	38,166	861,906	366,500	5,786,628
30	2007	MDU Resources/ Cascade Natural Gas	117,429	23,066	8,064	23,518	411	48,882	9,530	140,382
31	2008	Great Plains (Kansas City Power & Light)/ Aquila Inc. (MO)	680,280	199,169	62,285	81,917	1,525	250,520	32,692	1,474,527
32	2008	MDU Resources/ Intermountain Gas	109,726	21,274	7,470	23,909	335	44,067	10,877	137,680
33	2011	AES Corporation/ DPL Inc.	721,426	266,844	116,503	68,010	-	194,316	75,565	1,792,979
34	2011	FirstEnergy Corp./ Allegheny Energy, Inc.	2,325,069	436,074	573,649	398,115	3,215	489,863	420,838	9,860,737
35	2012	Northeast Utilities/ NSTAR	1,914,227	73,016	429,235	371,870	2,979	518,942	514,879	4,292,814
36	2012	Exelon Corporation/ Constellation Energy Group, Inc.	2,797,074	-	536,111	842,395	1,271	747,123	664,134	8,246,928
							(column not used)			(column not used)

Reported Costs Close + 3 yrs (in $ of -1 year)

Trans-action Number	Deal Year	Buyer Name/ Target Name	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	A&G O&M	Cust Svc	Electric O&M
1	1997	Ohio Edison Company/ Centerior Energy	1,867,452	1,117,542	94,905	194,056	59,121	314,372	87,457	3,164,573
2	1997	Puget Sound Power & Light Company/ Washington Energy Co	425,421	132,030	-	86,305	5,166	126,548	51,172	1,633,641
3	1998	Brooklyn Union Gas/ Long Island Lighting Company	563,039	-	9,745	147,479	24,629	252,019	12,571	-
4	1998	LG&E Energy LLC/ Kentucky Utilities Company (KU)	501,252	162,372	23,495	71,340	324	199,165	28,909	1,539,485
5	1998	Pacific Enterprises/ Enova Corporation	1,456,195	104,326	142,059	334,992	4	593,530	177,494	-
6	1998	Union Electric Company/ CIPSCO Inc.	1,098,393	368,284	33,328	217,099	3,345	404,919	79,496	2,740,106
7	1999	Consolidated Edison Company of New York/ Orange and Rockland Utilities, Inc.	1,246,915	-	192,290	575,530	1,730	255,116	270,980	5,612,616
8	1999	Delmarva Power & Light Company/ Atlantic Energy Inc.	374,244	-	22,407	98,545	-	124,406	87,009	1,914,820
9	1999	Nevada Power Company/ Sierra Pacific Power Company	711,402	406,785	27,525	52,150	383	177,189	47,369	3,413,168
10	2000	SCANA Corporation/ Public Service Company of North Carolina, Incorporated	323,301	132,931	9,939	27,860	3,601	110,776	38,194	772,119
11	2000	American Electric Power Company, Inc. (AEP)/ Central and South West Corporation	3,067,318	1,412,030	213,856	481,177	625	706,460	253,170	8,942,069
12	2000	Carolina Power and Light Company (CP&L)/ Florida Progress Corporation	1,707,589	696,080	97,233	186,712	18,396	517,997	191,172	4,941,712
13	2000	Unicom (Commonwealth Edison)/ PECO Energy	1,740,828	-	85,220	568,314	8,508	828,161	287,984	7,353,219
14	2000	Dominion Resources, Inc./ Consolidated Natural Gas Co.	1,332,296	273,933	68,625	423,004	2,121	451,549	100,923	5,119,316
15	2000	Energy East Corporation/ Central Maine Power Company	593,910	-	85,243	224,380	6,749	145,375	113,183	2,124,233
16	2000	Indiana Energy Inc./ SIGCORP, Inc.	218,189	53,344	2,505	45,359	1,078	85,176	19,146	554,325
17	2000	Northern States Power Company / New Century Energies, Inc.	2,269,846	956,491	254,926	261,731	10,912	533,689	241,219	6,547,748
18	2001	AES Corporation/ IPALCO Enterprises, Inc.	194,843	73,661	7,256	30,310	-	64,968	18,648	384,186
19	2001	FirstEnergy Corporation/ GPU, Inc.	1,929,251	-	446,992	386,333	4,577	587,285	264,002	7,436,596
20	2002	Potomac Electric Power Company/ Conectiv Energy, Inc.	755,689	183,395	44,309	157,838	6,906	231,059	132,186	2,982,669
21	2003	Ameren Corporation/ CILCORP, Inc.	1,214,123	347,116	52,633	289,772	2,311	400,492	93,414	3,440,558
22	2004	Northeast Utilities/ Connecticut Valley Electric Co Inc.	939,743	68,014	199,861	169,086	337	272,359	226,577	3,664,589
23	2004	Ameren Corporation/ Illinois Power Company	1,553,526	368,449	90,038	436,731	2,436	509,579	131,052	5,106,427
24	2005	PNM Resources Inc./ TNP Enterprises, Inc.	560,774	209,627	98,106	69,035	5,479	154,550	28,879	1,527,997
25	2006	Duke Energy/ Cinergy	2,983,843	1,293,191	122,891	373,247	774	981,891	182,947	6,563,023
26	2006	Midamerican Energy/ PacifiCorp	1,661,414	640,508	228,839	308,591	6,589	253,821	219,772	3,730,032
27	2006	UGI Corporation/ PG Energy	174,149	-	6,022	43,179	1,530	70,324	25,706	110,556
28	2007	WPS Resources/ Peoples Energy Corp.	905,460	77,540	121,135	198,919	-	314,133	136,108	2,476,654
29	2007	National Grid/ KeySpan Corp	3,228,526	-	571,702	775,019	17,649	1,163,088	589,406	9,092,466
30	2007	MDU Resources/ Cascade Natural Gas	108,658	22,496	9,043	23,986	150	42,211	8,870	374,347
31	2008	Great Plains (Kansas City Power & Light)/ Aquila Inc. (MO)	616,995	225,016	51,021	76,173	1,067	214,645	45,579	1,271,701
32	2008	MDU Resources/ Intermountain Gas	106,756	22,496	9,043	23,986	150	42,211	8,870	125,062
33	2011	AES Corporation/ DPL Inc.	717,257	235,142	128,893	69,542	-	181,793	101,737	1,965,080
34	2011	FirstEnergy Corp./ Allegheny Energy, Inc.	2,799,555	476,343	693,714	407,615	1,407	748,903	471,041	6,481,372
35	2012	Northeast Utilities/ NSTAR	1,860,674	51,216	486,331	321,753	1,244	461,768	582,791	4,327,550
36	2012	Exelon Corporation/ Constellation Energy Group, Inc.	2,815,458	-	476,387	855,450	727	780,596	712,782	5,749,893
							(column not used)			(column not used)

(Table not used)

	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	A&G O&M	Cust Svc	Electric O&M
MinimumQrt 0 MIN	-33%	-567%	-44%	-23%	-100%	-57%	-38%	-76%
QRT 1 (25%)	-8%	-12%	-7%	-8%	-76%	-16%	-17%	-8%
QRT 2 (Median)	0%	-2%	11%	0%	-54%	-10%	0%	10%
QRT 3 (75%)	10%	8%	40%	7%	-27%	20%	9%	36%
QRT 4 (Max)	32%	541%	1186%	49%	423%	59%	282%	167%
IQR (internal quartiles range)	18%	21%	47%	15%	50%	36%	26%	44%
min non outlier	-35%	-43%	-78%	-30%	-151%	-69%	-56%	-75%
max non outlier	38%	39%	110%	30%	48%	73%	48%	103%

Min/Max and Quartile Breaks

	NF Electric O&M	NF Gen O&M	Trans O&M	Distrib O&M	Sales	A&G O&M	Cust Svc	Electric O&M
	-33.0%	-40.1%	-44.1%	-22.7%	-98.9%	-56.8%	-38.0%	-34.3%
	-7.9%	-11.9%	-8.6%	-8.8%	-72.7%	-16.0%	-18.5%	-9.2%
	-0.3%	-2.5%	10.1%	-0.5%	-56.2%	-10.0%	-3.7%	8.9%
	10.4%	7.7%	31.9%	3.7%	-39.9%	19.6%	8.0%	28.3%
	31.9%	25.2%	77.4%	23.7%	4.2%	59.0%	39.4%	57.1%
	18.3%	19.6%	40.5%	12.6%	32.8%	35.5%	26.4%	37.5%
	-35.4%	-41.2%	-69.4%	-27.7%	-121.9%	-69.2%	-58.1%	-65.4%
	37.9%	37.1%	92.6%	22.6%	9.2%	72.8%	47.6%	84.5%

	NF Electric O&M	NF Gen O&M	Trans O&M	Dist O&M	Cust Svc	A&G	Electric
Best	-33.0%	-40.1%	-44.1%	-22.7%	-38.0%	-56.8%	-34.3%
75th Percentile	-7.9%	-11.9%	-8.6%	-8.8%	-18.5%	-16.0%	-9.2%
Median	-0.3%	-2.5%	10.1%	-0.5%	-3.7%	-10.0%	8.9%
25th Percentile	10.4%	7.7%	31.9%	3.7%	8.0%	19.6%	28.3%
Worst	31.9%	25.2%	77.4%	23.7%	39.4%	59.0%	57.1%

Quartile Breaks for Bar Chart	NFOM	NF Gen O&M	Trans O&M	Dist O&M	Cust Svc	A&G	Check min/max					
Best	-0.3%	-2.5%	-8.6%	-0.5%	-3.7%	-10.0%	-33.0%	-40.1%	-44.1%	-22.7%	-38.0%	-56.8%
75th Percentile	-7.6%	-9.4%	-35.4%	-8.3%	-14.8%	-6.0%						
Median	-25.1%	-28.2%	10.1%	-13.8%	-19.6%	-40.9%						
25th Percentile	10.4%	7.7%	21.8%	3.7%	8.0%	19.6%						
Worst	21.5%	17.5%	45.5%	20.0%	31.4%	39.4%	31.9%	25.2%	77.4%	23.7%	39.4%	59.0%

Resorted for Chart	A&G	Cust Svc	Dist O&M	Trans O&M	NF Gen O&M	NFOM
Best	-10.0%	-3.7%	-0.5%	-8.6%	-2.5%	-0.3%
75th Percentile	-6.0%	-14.8%	-8.3%	-35.4%	-9.4%	-7.6%
Median	-40.9%	-19.6%	-13.8%	10.1%	-28.2%	-25.1%
25th Percentile	19.6%	8.0%	3.7%	21.8%	7.7%	10.4%
Worst	39.4%	31.4%	20.0%	45.5%	17.5%	21.5%

Verification of Response

Kansas City Power & Light Company

Docket No. 16-KCPE-593-ACQ

The response to BPU Data Request# 3-1A, submitted by KCP&L, is covered by this Verification of Response:

I have read the foregoing Information Request(s) and answer(s) thereto and find answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signed: William J Kemp

Title: Senior Managing Director

Date: December 13, 2016