

1 **Prepared Rebuttal Testimony of H. Edwin Overcast**

2
3 *I. Introduction*

4
5 **Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.**

6 A. H. Edwin Overcast, Director, Enterprise Management Solutions, a Black &
7 Veatch Company.

8 **Q. ON WHOSE BEHALF ARE YOU APPEARING?**

9 A. I am appearing on behalf of the Board of Public Utilities of the Unified
10 Government of Kansas City, Kansas and Wyandotte County, Kansas (“BPU”).

11 **Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS**
12 **MATTER?**

13 A. Yes. I sponsored testimony initially related to both the cost of service study and
14 the proposed rate design.

15 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

16 A. The purpose of my testimony is to address issues raised by the industrial
17 interveners related to the proposed “Rate Plan” (consisting of a series of four rate
18 increases over four years designed to recover the prudently incurred costs and to
19 meet the minimum financial requirements to maintain the current favorable bond
20 rating and to increase liquidity) developed by the BPU Staff and Black & Veatch
21 working together. I will address a variety of issues related to utility regulation
22 based on considerations that the Board of the BPU should use in evaluating the
23 merits of the proposed Rate Plan. In addition, I will respond to issues related to
24 the cost of service study and rate design raised by the Industrial interveners.

25 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

26 A. My testimony is organized in eight sections as follows:

27 I. Introduction

28 II. Regulatory Issues Related to Proposed Expenses

29 III. The Evaluation of the Proposed Capital Budget

30 IV. The Issues Resulting from Current Financial Ratings

31 V. The Elements of the Rate Plan

1 VI. Electric Cost of Service Issues

2 VII. Rate Design Issues

3 VIII. Summary and Conclusions

4 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

5 A. My testimony provides evidence that the proposed BPU Rate Plan:

- 6 1. Provides revenue requirements consistent with sound economic
7 assumptions
- 8 2. Represents a thorough and competent plan to restore minimum financial
9 metrics consistent with maintaining the current bond rating
- 10 3. Begins to restore and enhance infrastructure consistent with safe and
11 reliable utility service.

12 My testimony provides evidence that the Industrial intervener's criticisms of the
13 cost of service study are based on erroneous assumptions, poor application of the
14 theory of cost of service or departure from fundamental principles such as cost
15 causation. Finally, I provide additional support and evidence to oppose various
16 proposed changes advanced by the Industrial interveners to the LPS rate and the
17 ERC and ESC riders.

18

19 *II. Regulatory Issues Related to Proposed Expenses*

20

21 **Q. IS THERE A STANDARD FOR REVIEW OF REGULATORY EXPENSES**
22 **THAT THE BOARD SHOULD ADOPT IN REVIEWING THE**
23 **REASONABLENESS OF THE EXPENSES CONTAINED IN THE**
24 **PROPOSED RATE PLAN?**

25 A. Yes. With respect to the proposed level of expenses, any necessary, legitimate
26 and ordinary expenses associated with providing safe and reliable utility service
27 should be allowed in rates. The fundamental question related to expenses in the
28 broadest sense is a question of fact. That is, are the facts supporting the proposed
29 level of expenses underlying the Rate Plan based on sound analysis and consistent
30 with the operating realities of the BPU? In developing the Rate Plan, the BPU
31 Staff and Black & Veatch relied on the approved budget for the current year and

1 prepared forecasts based on sound economic and financial principles for the
2 remainder of the Rate Plan. When expenses are properly incurred they must be
3 allowed in rates¹. Further, it is in the best interest of the BPU and its customers
4 for the BPU to maintain its strong bond rating based on the high degree of
5 leverage required to support the capital plan. It is also inappropriate to forecast
6 expenses based solely on a period where financial distress resulted in abnormally
7 low expenses in critical areas such as plant maintenance.

8 **Q. ARE THERE ACCEPTED STANDARDS FOR THE EXCLUSION OF**
9 **EXPENSES FROM RATES?**

10 A. Yes. The common standards for excluding expenses from rates fall into five
11 categories each of which requires competent evidence to reject recovery of the
12 expenses. The five categories are as follows:

- 13 1. The expenses are imprudent or inefficient
- 14 2. Managerial discretion has been abused
- 15 3. The expenses are arbitrary or harm the public interest
- 16 4. The expenses are wasteful
- 17 5. The expenses represent payments in excess of just and reasonable charges².

18 Using these five criteria to assess the proposed expenses of the plan allows the
19 Board to assess whether the proposed plan is just and reasonable in regard to the
20 level of expenses included in the plan for each year of the proposed plan.

21 **Q. IS THERE ANY REASON TO BELIEVE THAT THE BOARD SHOULD**
22 **SUBSTITUTE THE JUDGMENT OF AN INTERVENER AS TO WHAT**
23 **THE LEVEL OF OPERATING EXPENSES OUGHT OT BE?**

24 A. No. It is the responsibility of the BPU management to manage the expense levels
25 not to have an intervener substitute its judgment for that of management. Even
26 state and federal regulators charged with the oversight of utility rates may not
27 "usurp the powers of management."³ Even with all of the responses provided by
28 the BPU to the intervener experts, those experts have no basis for dictating
29 expense levels to the BPU or the Board absent competent evidence that the

¹ See for example *Mississippi River Fuel Corp. v. FPC*, 163 F.2d (D.C. Cir. 1947)

² Based on Principles of Public Utility Regulation, A. J. G. Priest, The Michie Company, 1969, p.51

³ *Op. cit.*, p. 50.

1 expense levels violate one or more of the five factors that permit disallowance of
2 the expenses. Interveners are simply not in the position to assess appropriate
3 expense levels whether it relates to the number of employees or their
4 compensation or any other legitimate expense incurred to operate and maintain
5 the BPU system.

6 **Q. WHAT ARE THE BASES FOR THE INTERVENERS OBJECTIONS TO**
7 **EXPENSE LEVELS?**

8 A. Industrial interveners have adjusted expenses on several bases. First, the
9 assumption related to the growth in non-payroll O&M was altered based on a
10 review of the budgeted non-payroll O&M for 2008 and 2009. Using this data
11 from a period in which the BPU was forced to operate on an austerity budget due
12 to its cash flow position is not consistent with the concept of reflecting the most
13 reasonable operating budget. The Industrial interveners' assumption effectively
14 forces the BPU to operate with an unacceptably low level of O&M expenses
15 going forward because they were able to operate that way for several years as they
16 managed their insufficient cash position. Second, the Industrial interveners
17 propose to eliminate a number of positions from the budget. They argue that it is
18 imprudent to hire additional employees because of the state of the economy. The
19 mere assertion of imprudence does not constitute evidence of imprudence. The
20 Industrial interveners have provided no evidence that these positions are not
21 needed or that it is wasteful to hire additional employees. Essentially, the
22 evidence they provide is that if the BPU had more revenue it could hire the
23 employees and a disagreement over the timing of those revenue increases does not
24 mean that the expenditures should not be included in rates.

25 **Q. HAS THE BPU PROVIDED EVIDENCE THAT THE PROPOSED**
26 **EXPENSE LEVELS IN THE RATE PLAN ARE REASONABLE AND**
27 **BASED ON SOUND ANALYSIS?**

28 A. The BPU has provided a full report describing the process used to determine
29 expense levels for each year of the Rate Plan. The BPU filed both a
30 comprehensive report prepared by Black & Veatch (**Electric Utility**

1 **Revenues, Revenue Requirements, Cost of Service, and Rates)** as well as
2 testimony from both the BPU Staff and Black & Veatch that described the
3 process used to develop the expenses and the underlying assumptions used to
4 forecast expenses in each year of the Rate Plan. The issue with forecast expenses
5 is whether the forecasts are reasonable based on the facts and evidence provided
6 to support the forecast. In the case of the BPU rate plan where the rates
7 established in this process are the maximum amounts that may be charged in each
8 year, if the adjustments result in lower liquidity and debt coverage the only
9 available remedy for the Board is to go through another rate hearing process. If
10 the rates result in more revenue than needed, the Board may reduce the
11 prospective increase without a hearing. This possibility is unique to a municipal
12 utility and by using this provision the Board can completely mitigate the risk of
13 excess revenues but cannot mitigate the risk of too little revenue without the time
14 and cost of a complete new rate setting proposal. In the interim, if rates fail to
15 meet financial goals bond ratings may be lowered and costs will increase.

16 **Q. DOES BLACK & VEATCH SUPPORT APPROVAL OF A METHOD TO**
17 **SPECIFICALLY ALLOW FOR CREDITS TO FUTURE RATES IF THE**
18 **RESULTS OF THE PROPOSED RATES RESULT IN HIGHER THAN**
19 **REQUIRED FINANCIAL METRICS?**

20 A. Yes. The BPU Staff has included just such a proposal in its rebuttal testimony.

21 **Q. WHY HAS THE BPU STAFF PROPOSED ANNUAL EXPENSE**
22 **ADJUSTMENTS AS PART OF A MULTI-YEAR RATE PLAN?**

23 A. The multi-year rate plan is a common approach for municipal utilities that do not
24 have the resources to develop and pursue annual rate increase proposals. This
25 concept is explained more fully in the Black & Veatch report referenced above.
26 Importantly, when the precarious financial condition of the BPU is considered in
27 conjunction with the current state of the economy, it was in the interest of
28 customers to restore the utility to the minimum financial metrics required to
29 maintain the current bond rating including debt coverage and days of operating
30 cash reserves to improve liquidity through a series of annual increases rather than
31 restoring the financial metrics in the first year. (It is likely that if the BPU were

1 an investor owned utility that the proposed increase for this year would have been
2 far higher than the increase under the plan.) In addition, debt service related costs
3 represent a significant portion of the revenue requirements and there will be
4 multiple new issues over the Rate Plan period that must be included in the costs to
5 meet debt service payments and bond coverage. Given the annual increases
6 associated with debt issues, it is also necessary to reflect expense increases or
7 there would be insufficient cash to maintain bond coverage and adequate
8 liquidity.

9

10 *III. The Evaluation of the Proposed Capital Budget*

11

12 **Q. PLEASE DISCUSS THE STANDARD THE BOARD SHOULD USE TO**
13 **EVALUATE THE PROPOSED CAPITAL BUDGET.**

14 A. The capital budget consists of several components each of which must be
15 evaluated separately to determine if the expenditures are prudent and efficient.
16 Those components include infra-structure replacement, load growth, capacity
17 expansion and reliability/system management. Although each category represents
18 new capital, the underlying rationale varies. In the case of infra-structure
19 replacement, the decision has a reliability component, a repair or replace
20 component and a modernization component related to efficiency and economic
21 savings. The load growth component is not discretionary and occurs when new
22 areas within the system are developed. Even if overall growth does not occur
23 there are areas where new loads are added and the infra-structure must be built to
24 serve the new load as part of the utility obligation to serve. Growth investment
25 potentially includes transmission facilities and always includes distribution
26 facilities. Capacity expansion is driven by forecast peak loads. It is also driven
27 by the need to replace older less efficient capacity or a combination of growth and
28 replacement. Capacity additions are lumpy in that the most efficient alternative
29 for new capacity may be larger than load growth in the target year when new
30 capacity is required. Nevertheless, adding capacity in a timely manner is the most
31 efficient decision. It may also permit unit retirements of older less efficient
32 (higher cost) units and avoid capital investment required to extend the older units

1 life. For reliability and system management, investments are designed to reduce
2 the costs of outages improve the quality of service and to improve overall system
3 efficiencies. Where the proposed capital budget is supported by these individual
4 components, it represents appropriate capital costs for inclusion of the funding
5 costs in rates. The capital budget also necessarily meets the utility obligation to
6 provide safe, reliable and cost effective service.

7 **Q. DOES THE MANDATE THAT REGULATORY AGENCIES REFRAIN**
8 **FROM MANAGING THE UTILITY APPLY TO CAPITAL AS WELL.**

9 A. Yes. It is not the purpose of regulation to determine if capital costs should or
10 should not be incurred except in the circumstances where regulation includes a
11 review and approval of the utilities capacity expansion plans or the utility seeks
12 preapproval of a capital addition to reduce the risk of the regulatory agency
13 finding the invest imprudent or not used and useful. For investor owned utilities,
14 the grounds for not including capital costs in rates are that the costs were not
15 prudent either because the costs were not necessary or that the costs were higher
16 because of imprudent management. Cost may also be excluded because the plant
17 is not used or useful. Thus where the capital costs represent costs that are used
18 and useful and prudently incurred the capital cost should be included in rates.
19 The way that BPU capital costs are included in rates is through the carrying cost
20 of the capital which for the BPU is through debt service.

21 **Q. IS IT APPROPRIATE REGULATORY POLICY FOR INTERVENERS TO**
22 **PROPOSE LIMITS ON THE AMOUNT OF CAPITAL EMPLOYED BY**
23 **THE UTILITY SOLELY FOR THE PURPOSE OF REDUCING RATES?**

24 A. No. Reducing rate levels based on arbitrary limits to capital expenditures is not
25 sound policy. It is impossible for interveners to manage the utilities expected
26 capital requirements without substituting their judgment for that of the utility
27 management and the Board. As a practical matter, there is no procedure under
28 municipal regulation to adjust capital unless the interveners provide evidence that
29 specific elements of the proposed capital budget are unnecessary and should be
30 removed or that the capital expenditure can be successfully delayed for good
31 cause. The convenience of one group of customers, no matter how large the

1 customers usage, is not a valid ground for removing capital cost from rates. (For
2 example, Mr. Gorman talks about the state of the economy and states that it would
3 be unreasonable for the BPU to fully restore its financial health while its
4 customers struggle but this is not the BPU proposal.) Mr. Gorman also states the
5 following:

6 The BPU's distressed service area economy simply cannot afford this
7 massive increase to the CIP proposed by BPU Staff and Black & Veatch
8 over the next five years. Therefore, the CIP should be moderated to
9 substantially mitigate the rate increase the BPU Staff and Black & Veatch
10 are proposing to impose on the BPU service area economy

11 This statement does not constitute evidence that the capital program is imprudent
12 or even unnecessary. Additionally, Mr. Gorman spends several pages of his
13 testimony discussing how the Board should manage the BPU capital budget to
14 meet his objective of mitigating the proposed rate increase. Mr. Gorman's
15 concern is not directed at whether the expected level of cost is prudent or the
16 service will be used and useful. It is simply impossible for Mr. Gorman to
17 adequately plan the system from his perspective as a representative of a customer
18 group that wants to keep rates as "low as possible." The strategy of keeping rates
19 as low as possible is the essence of how the BPU got to this financial position to
20 begin with. They have deferred capital cost and expenses consistent with the
21 level of revenues resulting from lower rate increases negotiated by the industrial
22 customers. This has had multiple effects including poor financial metrics,
23 increased capital costs for infrastructure projects, and higher capital expenditures
24 to catch up with deferred capital projects.

25 **Q. DO CUSTOMERS GENERALLY WANT TO KEEP "RATES AS LOW AS**
26 **POSSIBLE"?**

27 A. No. In addition to rate levels customers want reliable service with a minimum of
28 outages and voltage fluctuations. Power quality is an important issue for
29 customers of all sizes but in particular for larger customers. Customers also want
30 rates to be reasonable over the long run not just in one given year. This means
31 that the utility must be sound financially so that their cost of debt capital is

1 reasonable. In this regard, both the utility and its customers really want rates to
2 be based on the “best cost”. Best cost means that the utility is efficiently run and
3 provides safe, reliable, high quality power while managing the utility consistent
4 with sound financial metrics and efficient capital planning. This goal is
5 inconsistent with the concept of “rates as low as possible” since that concept
6 would cause the utility to defer maintenance, postpone needed capital additions,
7 allow power quality to deteriorate, reduce levels of reliability and so forth. It
8 would also cause the utility to downgrade its financial metrics and increase the
9 long run cost of utility service. The concept of “rates as low as possible” is
10 inconsistent with an efficient, well run utility operation.

11 **Q. IS AN INCREASE IN THE ANNUAL CAPITAL BUDGET OVER PRIOR**
12 **YEARS EVIDENCE THAT THE CAPITAL BUDGET IS**
13 **UNREASONABLE?**

14 A. No. As I noted earlier, utility capital additions are by their nature lumpy. This
15 simply means that capital requirements over time will be different based on the
16 particular circumstances faced by a utility. Looking at a historical period to
17 forecast current capital requirements results in an incorrect estimate of actual
18 capital requirements because of a number of factors. For example, even if the
19 BPU were to replace the exact same number and mix of transformers in the
20 current year as it did say five years ago, the capital budget for transformers would
21 be significantly different because the cost of transformers changed dramatically
22 over this period as the result of cost increases for inputs such as copper. Based on
23 BPU data, the cost of residential type pole top transformers has gone up over 35%
24 since 2007. So merely replacing the most commonly used transformers would
25 substantially increase the capital budget even without the need to catch up for
26 deferred capital items. In addition, whenever a utility adds generation capacity to
27 the system the capital budget must increase significantly.

28
29 *IV. The Issues Resulting from Current Financial Ratings*

30

1 **Q. PLEASE DISCUSS THE CURRENT FINANCIAL RATINGS FOR THE**
 2 **BPU.**

3 A. The BPU currently has a bond rating from each of three major rating agencies-
 4 Fitch Ratings, Moody’s Investor Service and Standard and Poor’s. The utility
 5 rating is one of the factors that influence both the cost of debt and the access to
 6 the capital markets. The table below shows the actual cost of debt for 2009 as a
 7 percent of revenues and the forecast cost of debt for 2010-2014 as a percent of the
 8 forecast revenue excluding fuel costs.

9 **Table 1**

Cost of Debt as a % of Total Non-Fuel Revenue Requirements

	2009	2010	2011	2012	2013	2014
Debt Service						
Existing	20,644,000	22,956,300	22,368,700	22,345,700	22,361,700	22,364,000
Proposed	-	-	3,659,500	9,503,900	11,781,000	13,689,200
Total	20,644,000	22,956,300	26,028,200	31,849,600	34,142,700	36,053,200
Total Non-Fuel Revenue Req.	119,768,700	127,708,300	137,446,300	152,922,100	160,211,100	164,851,100
Debt Service %	17.2%	18.0%	18.9%	20.8%	21.3%	21.9%

10

11

12 As the table illustrates the cost of debt represents an average of almost 20% of
 13 non-fuel revenue requirements and is a significant element of the costs on which
 14 rates are based. It is important to understand how rating agencies evaluate the
 15 utility to determine the rating and to be aware of these requirements in analyzing
 16 the BPU Staff Plan and the Plan presented on behalf of the industrial interveners.

17 **Q. WHAT ELEMENTS ARE CONSIDERED BY THE RATING AGENCIES**
 18 **IN DETERMINING BOND RATINGS?**

19 A. Fitch Ratings published their “**Public Power Rating Guidelines: Rating Criteria**”
 20 in June of 2009. A copy is attached as Schedule 1 of the exhibit to this testimony.

1 This eight page description of the rating process provides insight into the
2 mechanics of the rating determination and covers a broad range of issues beyond
3 those strictly quantitative provisions such as coverage and days of operating cash.
4 Some of the more important points in the criteria include the following:
5

- 6 A. Quality of senior management and the utility’s governance body (e.g.,
7 board of directors, city council, or other) is a key consideration in the
8 Fitch analytical process. Management’s ability to design a thorough
9 strategic plan that is appropriate for its particular needs and its ability to
10 successfully implement that plan carry great weight in the rating process.
11 A high level of board understanding of the issues facing the utility and the
12 system’s business strategy is just as important. Fitch reviews
13 management’s past performance to see how well they have met its goals
14 and objectives. (Emphasis added.)
- 15 B. Fitch looks to get a full understanding of the utility’s debt management
16 policies and whether the rationale for the proposed debt and/or capital
17 addition are compliant with all relevant legal requirements and system
18 needs; that the utility demonstrates the ability and willingness to recover
19 costs in a timely manner; and that the structure of debt (e.g., fixed vs.
20 variable) can be adequately supported without undue strain to the utility’s
21 cash flow and liquidity. (Emphasis added.)
- 22 C. Fitch’s analysis of the distribution operations includes an assessment of
23 reliability, maintenance and expansion requirements of the system.
- 24 D. System performance that is in line with or better than industry standards
25 can provide support for a strong credit rating. However, below-average
26 reliability levels and inadequate investment in the system can place
27 negative pressures on a utility’s financial performance as a result of less-
28 efficient cost recovery. Additionally, system outages or line losses, and
29 subsequent customer dissatisfaction, could result in the political
30 unwillingness to support a utility’s future rate requests.

1 E. The measure of rate flexibility is not based solely on the affordability
2 measures, but includes an emphasis on legal ability and political
3 willingness to enact rate increases.

4 F. As important to the level of equity as a percentage of capitalization are the
5 system's operating leverage ratios, and the plan to grow system equity or
6 the competitiveness of the system's cost structure, which could be viewed
7 as hidden equity that can be tapped into if needed.

8 As these quotes indicate the overall plan to return the BPU system to financial
9 health and to meet the requirements to maintain the system are significant issues
10 relative to financial ratings along with the quantitative measures of days of
11 operating cash and debt coverage ratio. Mr. Gorman has effectively ignored the
12 reality of the rating process and seeks to focus solely on the two financial metrics.
13 The significant downward pressure on rates and capital for maintaining the
14 system and meeting new requirements is contrary to a sound long term plan as
15 explained in detail by the BPU Staff. Further, the Industrial interveners have
16 taken the position that the Environmental Surcharge Rider should allow no more
17 than a five percent cash contribution as part of the funding. This is the equivalent
18 of a five percent equity ratio for the financing of environmental capital projects.
19 This is inconsistent with a reasonable level of equity to support the capital
20 program. The five percent is arbitrary and any attempt to force an unreasonably
21 low level of equity should be rejected.

22 **Q. PLEASE DISCUSS THE FINANCIAL METRICS THAT THE BPU STAFF**
23 **HAS INCLUDED IN THE RATE PLAN.**

24 A. The BPU Staff, consistent with Board policy and bond covenants have
25 recommended that the minimum bond coverage should be 1.6 times interest
26 expense and that the days of operating cash equal 60 days. Over the Rate Plan
27 period the proposed increases essentially satisfy these two financial objectives
28 under the circumstances that the BPU has forecast. It is important in reviewing
29 the plan that these two objectives represent the minimum levels consistent with
30 the current financial rating. Importantly, these target metrics create no
31 opportunity to respond to financial contingencies such as higher bond interest

1 rates, ice storms, larger contributions to pension funds or other major expenses
2 not included in rates. Intuitively, one would expect higher not lower interest rates
3 for two reasons. First, interest rates are at near record low levels currently.
4 Second, during the term of the Rate Plan large amounts of existing debt will need
5 to be refinanced by all sectors of the economy putting pressure on interest rates to
6 balance supply and demand. The need for contingencies in a cash financed utility
7 is imperative. Whereas a state regulated utility might get permission to defer
8 extraordinary costs for amortization over some future period, the BPU does not
9 have the ability to create a regulatory asset for amortization because they operate
10 on a cash basis. Thus an ice storm that damages the delivery system will require
11 cash to restore the system. Similarly, any large, unforeseen expense for the BPU
12 such as a turbine replacement in a power plant or large increases in benefits cost
13 such as healthcare would prevent the BPU from meeting its financial goals over
14 this period. It is significant that the risks of failing to meet the financial goals is
15 likely to be higher than the risk that the utility exceeds the goals for all the reasons
16 discussed above.

17

18 *V. The Elements of the Rate Plan*

19 **Q. PLEASE SUMMARIZE THE ELEMENTS OF THE BPU PROPOSED**
20 **RATE PLAN.**

21 A. The proposed rate plan is a carefully crafted plan designed to restore financial
22 metrics to levels consistent with maintaining the current bond rating. Restoring
23 the financial metrics occurs through a series of annual rate adjustments designed
24 to recover the expected costs for each year of the plan from the number of
25 customers and sales in that year which form the basis for the expense levels in
26 that year. In addition to restoring the financial health of the utility, the plan
27 correctly recognizes that ultimately dollars to restore the financial metrics are
28 residual dollars after the payment of all expenses including debt service costs and
29 raising adequate dollars retained to maintain a sound capital structure to support
30 new investment.

1 **Q. WOULD IT HAVE BEEN POSSIBLE TO RESTORE THE FINANCIAL**
2 **METRICS IN A ONE YEAR TEST PERIOD?**

3 A. Yes. The BPU Staff could have proposed to restore the financial metrics in a
4 single year. This would have necessitated a single large increase followed by
5 annual adjustments designed to maintain those targets in subsequent years as new
6 debt was issued and additional operating expenses incurred. Such an option
7 would be more expensive as the result of the costs of annual rate proceedings.
8 That option would have meant far larger a rate increase in the initial year than
9 under the plan and would adversely impact customers who faced such a large
10 increase in that year.

11 **Q. IS IT COMMON FOR UTILITIES TO PROPOSE PLANS THAT PHASE**
12 **IN LARGE RATE INCREASES OVER SEVERAL YEARS RATHER**
13 **THAN INCREASE RATES ALL AT ONCE?**

14 A. Yes. Utilities recognize that under some circumstances large rate increases may
15 need to be phased in over time to permit customers to adjust gradually to higher
16 rates. The BPU Staff proposed just such a phase in of increases in the Rate Plan.
17 Instead of restoring the financial metrics in the first year the Rate Plan does so
18 over a future, reasonably long period. Specifically, the BPU Staff recognizes that
19 there is no ideal time to raise rates to customers. However, without the proposed
20 Rate Plan to do so the cost of financing new capital requirements will increase
21 and the quality of service measured by factors such as reliability and power
22 quality will deteriorate. As described by the BPU Staff in detail, the Rate Plan
23 sets minimum requirements for maintaining a favorable financial rating and
24 operating a reliable, efficient and safe system over the Rate Plan period. The Rate
25 Plan is the best option for managing the BPU system over the next few years
26 while minimizing the cost for customers consistent with Board policies on
27 financial metrics and operating the system to meet customer requirements.

28

29 *VI. Electric Cost of Service Issues*

30 **Q. HAVE THE INDUSTRIAL INTERVENERS IDENTIFIED ISSUES WITH**
31 **THE COST OF SERVICE STUDY PROVIDED IN THE REPORT?**

1 A. Yes. Both Mr. Gorman and Ms. Myrick have identified a variety of issues with
2 the cost of service study. As a result of their proposals they argue that increases
3 should be across the Board and that an alternative allocation methodology be
4 approved. They argue that the development of allocation factors for the various
5 classes of service are unreliable and as a result have presented their own modified
6 cost of service study. I will demonstrate that the cost of service study filed with
7 the Board as part of the initial report is reliable, favors the industrial customers
8 relative the option recommended by Ms. Myrick and that the methodology has
9 been accepted by the Kansas Corporation Commission in its most recent decision.
10 I will also discuss the flaws in the method proposed by Ms. Myrick and
11 demonstrate that the results of her preferred methodology would be very different
12 than she characterizes it if the method reflects cost causation for the BPU.

13 **Q. PLEASE DISCUSS THE ISSUES RAISED BY MS. MYRICK.**

14 A. Ms. Myrick claims that the Average and Excess Demand (AED) method used by
15 Black & Veatch is not a generally accepted method in Kansas and that she cannot
16 state whether it is a generally accepted method on a broader basis than the
17 parochial interests of Kansas. She further states that the AED method has not
18 been adopted in Kansas. Ms. Myrick opines that the method does not provide an
19 equitable method to allocate costs for the BPU. As a result, she advocates a
20 method identified as Peak and Average/4 Coincident Peaks (P&A/4CP). In her
21 discussion of the method used in the Black & Veatch report, Ms. Myrick
22 mischaracterizes the AED method as a basis for her concern about the
23 appropriateness of the method. Ms. Myrick concludes by recommending the
24 P&A/4CP methodology without providing any support for the method other than
25 it is the method used by the Kansas staff. Indeed this same method was filed by
26 the KCC Staff in the most recent case where the AED methodology was adopted.

27 **Q. IS THE AED METHODOLOGY USED BY BLACK & VEATCH WIDELY
28 ACCEPTED AS A REASONABLE METHOD?**

29 A. Yes. Ms. Myrick needs to look no further than the Electric Utility Cost Allocation
30 Manual published by the National Association of Regulatory Commissioners
31 (NARUC) where the AED method is discussed at length. Beginning at page 53 of

1 the manual, there is a discussion of energy weighting methods for allocating
2 production plant. In the introduction, the following statement is made: “There is
3 evidence that energy loads are a major determination of production plant costs.”⁴
4 This statement is precisely the basis for the adoption of the AED methodology as
5 discussed at length in my initial testimony supporting the cost of service study.
6 The peak and average method recommended by Ms. Myrick is discussed in the
7 same section of the manual as an alternative to AED under the heading of
8 “Judgmental Energy Weightings”⁵. In the most recent decision of the Kansas
9 Corporation Commission (KCC), the KCC adopted the Empire District Electric
10 Company (Empire) cost of service study. The KCC order in that case is attached
11 as Schedule 2 of my exhibit and the relevant portion of the order is found on page
12 10. The Empire cost study adopted in this order used the AED methodology.
13 While the Staff proposed P&A/4CP that method was not the option adopted by
14 the KCC.

15 **Q. DOES THE P&A METHOD HAVE DEFICIENCIES THAT WOULD**
16 **PRECLUDE ITS USE AS AN ALTERNATIVE TO AED IN THIS CASE?**

17 A. Yes. Ms. Myrick recommends a method that does not reflect cost causation and
18 suffers from theoretical shortcomings as well. For example, under the P&A/4CP
19 method, the 4CP component does not consider the total demand on system
20 resources but rather looks only at the demand based on load. The total demand on
21 system capacity consists of customer load, unit deratings, partial deratings, forced
22 outages and scheduled outages. System planners use all of this information in
23 selecting the appropriate mix of capacity for the system. When considering the
24 total load on the system, it is this total demand that drives cost not just the peak
25 hour during a four month period. In fact, for the BPU system, the total demand as
26 identified above based on 2009 actual data is highest in the months of June, July,
27 March and April. The explanation for this is really simple. Whenever large
28 baseload units are taken out of service for scheduled maintenance there is a
29 significant demand on the available system capacity. Moreover, the concept that

⁴ NARUC Electric Utility Cost Allocation Manual, 1991, p. 53

⁵ Op. cit. p.61

1 gas turbines run only during peak load periods and thus should be allocated on CP
2 demand is also incorrect. While it is true that gas turbines or other peaking units
3 run mostly during peak hours, peaking units also run in other hours that may not
4 be considered peak hours in response to large and rapid changes in load. Thus,
5 even for peaking units it is not purely peak loads that require peaking capacity.
6 The P&A/4CP methodology also suffers from a logical inconsistency based on
7 the fact that it uses the system average demand twice in developing its allocation
8 factors. The method uses average demand to develop the classification of
9 production costs between demand and energy. It is the average demand
10 component that determines the portion of baseload plants that are classified as
11 energy under the P&A/4CP method because load factor is defined as average
12 demand divided by maximum demand. The method determines the share of
13 average demand for each rate class as a percent of system average demand. This
14 becomes the allocation factor for the percentage of production judgmentally
15 classified as energy and allocated on energy. The P&A/4CP then uses the class
16 contribution to the 4CP allocation factor to allocate the portion of plant related to
17 demand which is the residual of the classification process that assigned the load
18 factor portion to energy. The 4CP allocation factor is mathematically the sum of
19 the average demand and the demand in excess of the average demand. The
20 classification argument is that average demand relates to baseload capacity and
21 that peaking capacity is built to serve loads in excess of the average or the
22 remainder of the production costs not classified as energy. Conceptually, it is
23 inconsistent to allocate a portion of cost on average demand and then use that
24 same average demand as a part of the allocation of the residual costs supposedly
25 based on the excess demand above the average. It is not the average demand
26 component that causes the cost for peaking services it is the excess demand or the
27 remainder of demand that causes the investment in peaking resources. By using
28 the average demand component for allocating the load factor related portion of
29 plant (the plant classified as energy) and excess demand to allocate the portion
30 classified as demand, the actual cost causation is reflected. In fact, this is exactly

1 the AED method. That is for the portion of production plant classified as demand
2 (everything but fuel handling plant) it is a demand allocation factor that is used.

3 **Q. DO YOU BELIEVE THAT THE CONCERNS EXPRESSED ABOUT THE**
4 **PROPOSED AED ALLOCATION MAY STEM FROM A**
5 **MISUNDERSTANDING OF THE METHOD?**

6 A. Yes. It is possible that the conclusions related to the AED method may stem from
7 various misunderstandings. Ms. Myrick compares the P&A/4CP method based
8 on an incorrect system load factor to the AED results. Instead of using the correct
9 system load factor of 56% Ms. Myrick uses the NCP load factor of 48%. The
10 actual system load factor must be calculated from the average demand of 280,650
11 kW divided by the system peak demand of 501,000 kW for a system load factor
12 of 56%. She has also failed to understand that the baseload plants of the BPU
13 system account for 76.78% of the plant investment. As a result of these facts
14 coupled with a correction of the 4CP allocation factor to actually reflect the
15 demand on capacity not just load, the cost allocation factors would be very
16 different than proposed by Black & Veatch. The following table provides a side
17 by side comparison for all rate classes except lighting since the 4CP allocation of
18 the demand component would not allocate any production demand costs to the
19 lighting customers.

20 **Table 2**

Comparison of Allocation Factors by Rate Schedule

Rate Class	AED	P&A/4CP
Residential	26.20%	28.99%
SGS	11.80%	10.07%
LGS	28.50%	26.52%
LPS	26.30%	30.25%
Schools	2.90%	2.10%

21

22 As the table illustrates, the method recommended by Ms. Myrick produces higher
23 production allocation factors for residential and LPS customers. This higher
24 allocation of plant would translate into even lower returns than those produced by
25 the Black & Veatch cost study for the high load factor LPS class. Since Ms.
26 Myrick's concern is that the Black & Veatch method allocates too much cost to

1 the LPS class, it seems inconsistent to recommend a method that allocates even
2 more costs to those customers. This is just an example of the results when there is
3 no detailed study of cost causation and an analysis of the cost allocation method
4 that properly reflects cost causation.

5 **Q. ARE THERE OTHER ISSUES WITH MS. MYRICK'S REVIEW OF THE**
6 **COST STUDY?**

7 A. Yes. Ms. Myrick criticizes the Black & Veatch study because the transmission
8 plant is allocated the same as generation. This is another example of
9 misunderstanding cost causation. The BPU transmission system is predominantly
10 built to deliver power from its generation stations to its load centers. The system
11 has minimal capability to transmit power for others as is typical for most investor
12 owned utilities that Ms. Myrick is accustomed to regulating. The BPU
13 transmission system provides typically only delivery service for its own
14 generation and power supply contracts based on its own load. Other transmission
15 systems provide a variety of transactions such as delivery of power for others by
16 export services or the delivery of power from outside the system to others outside
17 the system. Since the BPU transmission system has limited use for other than
18 delivering to its own customers, allocating the transmission capacity consistent
19 with the allocation of production mirrors cost causation. Ms. Myrick also
20 assumes that the AED allocation factor is used for distribution. This is also
21 incorrect as explained in my testimony. Distribution plant is properly allocated
22 on both customer and demand and the demand allocation factor is the class NCP.
23 Contrary to Ms. Myrick's assertion, no distribution plant is allocated on energy.

24 **Q. IS THERE ANY RELEVANCE TO COMPARING THE BPU**
25 **ALLOCATIONS TO THE PROPOSED ALLOCATION FACTORS OF**
26 **OTHER UTILITIES?**

27 A. No. Presumably, all utilities follow the principle of cost causation and can
28 support the method they propose by a study of their own system's cost
29 characteristics. In fact, a review of the system and its planning characteristics is a
30 fundamental step in determining the cost methodology that best reflects the cost
31 of the system. Ms. Myrick makes no mention of her review of the BPU system

1 but merely supports a method she has employed previously. Black & Veatch has
2 analyzed cost causation for the BPU system and as explained in detail in our
3 report and my original testimony. The conclusion reached through that review is
4 that the AED methodology is widely accepted and sound for use in this case.
5 None of Ms. Myrick’s arguments provide any factual basis for rejecting the
6 proposed AED method. The proposed allocations produce reasonable results and
7 are superior to the alternative advocated by Ms. Myrick even for the class of
8 customers she represents.

9 **Q. DOES MS. MYRICK SUGGEST THAT IT IS INAPPROPRIATE TO USE**
10 **FORECAST COSTS IN A COST OF SERVICE STUDY?**

11 A. Yes. Ms. Myrick states that the KCC does not allow forecast costs in a cost of
12 service study. The simple fact is that in this regard, the KCC is just one data point
13 of many regulatory agencies for the BPU Board to consider. In fact, many
14 regulatory agencies allow both full and partial forecasts in cost of service studies.
15 For example, the Federal Energy Regulatory Commission permits fully forecast
16 cost of service studies. In addition, about half of the state commissions also
17 permit forecast data in the cost study. In this case, the forecast is appropriate
18 because it better represents what costs and revenues will be in the future when
19 new rates take effect than a historical period. Indeed the underlying purpose of a
20 test period is to forecast cost and revenues for the period in which rates will be
21 effective. The fact that Kansas uses historic data does not require the BPU Board
22 to use historic data. The use of historic data would merely continue the current
23 under recovery of costs.

24 **Q. DOES FORECAST DATA PRESENT “A GREAT OPPORTUNITY TO**
25 **HARM CUSTOMERS” AS MS. MYRICK CLAIMS?**

26 A. No. Any type of test year, forecast or historic, presents an opportunity for harm to
27 customers. However, if the Board properly reviews the components of each
28 annual rate increase under the Rate Plan, there is no reason to expect undue harm
29 to customers. Further, the Board always has the power to correct any undue harm
30 by lowering rate levels if some harm results from the Rate Plan. This is really a
31 meaningless statement without analysis to show the harm from a competent

1 forecast rather than an unsupported general statement about the forecast. It is also
2 true that a historic period can harm either consumers or the utility if the historic
3 costs are not representative of the actual costs incurred when rates are in effect.
4 As a result some states explicitly recognize the shortcomings of the test year
5 concept and allow regulated utilities to adjust rates based on a formula approach.
6 In at least one state- Alabama, this approach was the result of intervention by the
7 courts.

8 **Q. DOES MR. GORMAN ALSO DISCUSS ISSUES WITH THE COST**
9 **STUDY?**

10 A. Yes.

11 **Q. PLEASE DISCUSS MR. GORMAN’S RECOMMENDATION RELATED**
12 **TO THE COST OF SERVICE STUDY.**

13 A. Mr. Gorman recommends that the Board “reject the Black & Veatch cost of
14 service study because it does not accurately reflect the BPU system customer
15 loads and demands.” Mr. Gorman identifies his concerns as the use of borrowed
16 load data, using estimates of class load factors and using estimated class
17 coincident factors. Simply, Mr. Gorman would make it impossible for any utility
18 without an expensive load research program to develop a cost of service study.
19 As a practical matter, smaller utilities often borrow load research data from larger
20 utilities and use that borrowed data to develop cost of service studies. In fact, the
21 KCC has accepted cost studies based on borrowed data for electric utilities under
22 their jurisdiction.⁶ The issue with borrowed data is whether or not the data as
23 used reflects the characteristics of the customers on the system and is reasonable.
24 Based on Black & Veatch’s experience, each of the allocation factors has been
25 reviewed to assure that the results are consistent with the load characteristics of
26 each rate class.

27 **Q. IS THE ALLOCATION OF COST IN THE BLACK & VEATCH COST**
28 **STUDY PROBLEMATIC AS CLAIMED BY MR. GORMAN?**

29 A. No. Although Mr. Gorman is correct that Black & Veatch used representative
30 data by rounding class load factors (NCP data is estimated and CP data is not

⁶ Midwest Energy used load research data from Westar to file its electric cost of service study.

1 required to allocate costs when using AED), the most recent data filed in Kansas
2 for a contemporaneous period shows that the conservative assumptions made by
3 Black & Veatch are accurate. The following table provides a comparison of the
4 data used by Black & Veatch with load research data from the January 2010
5 Empire District Electric cost study filed in Kansas.

6 **Table 3**

7 Comparison of Black & Veatch Load factor Assumptions with Actual Data

Class	NCP Load Factor BLACK & VEATCH Cost Study	NCP Load Factor Latest Load Research
Residential	40.38%	41%
SGS	35%	43%
LGS	47.96%	54%
LPS	66.43%	59%

8
9 Based on the most recent data, it is safe to conclude that to the extent the
10 differences exist, they are small and result in lower costs for all of the rate classes
11 except the LPS class which would have a higher NCP demand and more costs
12 allocated to that class since a lower load factor for a given average demand means
13 a higher NCP demand. Further, the BPU information available for the LPS class
14 is more reliable because these customers have metering that collects hourly data.
15 Based on this actual data, the costs for the LPS class are lower than they would
16 have been using the borrowed data.

17 **Q. DOES MR. GORMAN PROPOSE A DIFFERENT COST OF SERVICE**
18 **METHODOLOGY AS RECOMMENDED BY MS. MYRICK?**

19 A. No. Mr. Gorman uses the AED methodology proposed by Black and Veatch
20 rather than the method advocated by Ms. Myrick. Instead of using their own
21 recommended method, Mr. Gorman makes a series of adjustments to the Black &
22 Veatch model. As discussed below, the adjustments he makes fail to measure up
23 to the fundamental standards of cost causation or they are wrong based on the
24 underlying data used by Mr. Gorman.

1 **Q. PLEASE DISCUSS THE FIRST ADJUSTMENT MR. GORMAN MADE**
2 **TO THE BLACK & VEATCH COST STUDY TO PRODUCE TABLE 6 IN**
3 **HIS TESTIMONY.**

4 A. Mr. Gorman proposes a series of seven adjustments to the Black & Veatch cost
5 study. The first adjustment proposed by Mr. Gorman is to classify all production
6 plant to demand instead of classifying a portion of the fuel handling plant to
7 energy. His rationale for this change is that this equipment is sized according to
8 maximum capacity and should be classified as demand. With respect to
9 environmental and fuel handling equipment the operation of this equipment is
10 related to the level of energy produced not the capacity of the plant. Specifically,
11 for environmental plant the option available to its construction and use is the
12 purchase of emission allowances. Those costs would be based on energy
13 produced since that determines the level of emissions. In fact, emissions are
14 related to energy not capacity. In addition, the use of fuel handling equipment is
15 also directly related to the production of energy as opposed to a measure of
16 capacity. This adjustment does not reflect cost causation and should be rejected.

17 **Q. PLEASE DISCUSS THE SECOND ADJUSTMENT MR. GORMAN MADE**
18 **TO THE BLACK & VEATCH COST STUDY TO PRODUCE TABLE 6 IN**
19 **HIS TESTIMONY.**

20 A. The second adjustment relates to the classification of certain operation and
21 maintenance expenses. Mr. Gorman suggests that these expenses should not be
22 classified as energy but as demand to match the way in which the plant was
23 allocated. He offers no evidence that the maintenance costs are driven by
24 capacity. In fact, maintenance costs result from energy production when one
25 considers factors such as hours of operation as a maintenance driver. Further,
26 equipment such as coal handling equipment is maintained based on the level of
27 energy production as well. As a result, the classification of these accounts as
28 energy matches cost causation. With respect to the costs for operation
29 supervision and engineering, it is common to allocate this overhead related cost
30 on the basis of the allocation of the costs actually supervised by this account. Mr.
31 Gorman's adjustment departs from cost causation and should be rejected.

1 **Q. PLEASE DISCUSS THE THIRD ADJUSTMENT MR. GORMAN MADE**
2 **TO THE BLACK & VEATCH COST STUDY TO PRODUCE TABLE 6 IN**
3 **HIS TESTIMONY.**

4 A. The third adjustment made by Mr. Gorman relates to the allocation of the margins
5 from off system sales. Mr. Gorman allocates these dollars on energy and supports
6 his argument based on the allocation of off-system sales margins by large investor
7 owned utilities. However, there is a fundamental difference between the off-
8 system sales made by large utilities and those made by the BPU. For large
9 utilities these sales are opportunity sales. That is, the sales are made based on
10 market conditions and typically without any capacity commitment on the part of
11 the utility. The BPU sales are contractual sales from specific capacity. That is,
12 BPU agrees to sell both energy and capacity from a specific unit when and if the
13 unit is operating. The allocation method for such unit commitments should
14 follow the allocation of the capacity to fairly credit the margins to retail customers
15 who have been allocated the plant capacity dollars. The Black & Veatch
16 allocation reflects cost causation while allocation on energy does not. It is also
17 interesting to note that Mr. Gorman does not want costs allocated on energy
18 because the higher load factor customers he represents have larger shares of cost
19 when energy allocators are used. When the allocation is for a credit, he supports
20 the use of energy because his clients receive a larger share of the credit. Black &
21 Veatch provides an internally consistent allocation of these costs by returning the
22 credits in the same way the underlying costs are allocated.

23 **Q. PLEASE DISCUSS THE FOURTH ADJUSTMENT MR. GORMAN MADE**
24 **TO THE BLACK & VEATCH COST STUDY TO PRODUCE TABLE 6 IN**
25 **HIS TESTIMONY.**

26 A. Mr. Gorman allocates cash financed capital costs associated with AMI directly to
27 meters on the basis that there is an agreement on how to allocate these dollars.
28 The allocation is not consistent with cost causation and Mr. Gorman misstates the
29 discussion with the BPU Staff. The only agreement related to AMI dealt with the
30 specific meter costs as such meters were installed. To the extent that the AMI
31 investment relates not to meters but to other parts of the system such as

1 infrastructure, the costs should not be directly assigned to meters. More
2 importantly, Mr. Gorman has removed the cost of the AMI capital budget as part
3 of his assessment of the electric capital program. As a result of the allocation of
4 the capital dollars to meters, Mr. Gorman effectively allocates \$3 million dollars
5 of general capital programs largely to the residential class and away from the LPS
6 customers. For this reason alone the recommended allocation is not based on cost
7 causation and does not meet the test of a reasonable allocation of cost.

8
9 **Q. PLEASE DISCUSS THE FIFTH ADJUSTMENT MR. GORMAN MADE**
10 **TO THE BLACK & VEATCH COST STUDY TO PRODUCE TABLE 6 IN**
11 **HIS TESTIMONY.**

12 A. Mr. Gorman proposes to adjust the residential class allocation factor because
13 “Black & Veatch utilized a 45% average load factor for the BPU residential class
14 when calculating the demand allocators for all classes within the cost of service
15 study.” This statement is incorrect. Black & Veatch used a residential class load
16 factor of 40.38% not 45%. (See Table 3 above.) Mr. Gorman proposes to adjust
17 the load factor to 35% based on data calculated from Missouri and Kansas cases
18 from periods largely outside the period used by Black & Veatch to develop
19 allocation factors. Two cases were from 2008 and two were from 2009. Based
20 on the testimony of Ms. Myrick regarding the use of historic data in a rate case, it
21 is reasonable to conclude the load data used in these studies is from 2007 and
22 2008. Further, Mr. Gorman fails to indicate the basis for the calculation of the
23 load factor whether it is the CP or NCP load factor. Finally, had Mr. Gorman
24 used the latest data filed in Kansas and approved by the Commission the Black &
25 Veatch data for residential is consistent with recent load research. Thus, this
26 adjustment is incorrect based on the initial premise and the actual load data
27 available.

28 **Q. PLEASE DISCUSS THE SIXTH ADJUSTMENT MR. GORMAN MADE**
29 **TO THE BLACK & VEATCH COST STUDY TO PRODUCE TABLE 6 IN**
30 **HIS TESTIMONY.**

1 A. Mr. Gorman adjusted the loss factor for Borderline sales based on a calculation of
2 the class weighted sales to borderline customers. In his adjustment, Mr. Gorman
3 weighted the losses by the number of primary customers multiplied by the
4 primary loss factor plus the remaining number of customers multiplied by the
5 secondary loss factor. It is logically incorrect to weight loss factors by the
6 number of customers unless all customers use the same number of kWh. I have
7 calculated the kWh weighted loss factors and used both a 3.3% and a 3.8% loss
8 factor for primary served customers. The resulting loss factor for Borderline sales
9 is between 3.7% and 4.1%. I conclude that the 4% loss factor is a reasonable loss
10 factor and is supported by the data.

11 **Q. PLEASE DISCUSS THE SEVENTH ADJUSTMENT MR. GORMAN**
12 **MADE TO THE BLACK & VEATCH COST STUDY TO PRODUCE**
13 **TABLE 6 IN HIS TESTIMONY.**

14 A. Mr. Gorman suggests that the use of a 100% coincidence factor is inappropriate
15 for lighting and for schools. He adjusts the coincidence factor to 80%. This
16 adjustment has the effect of increasing the class non-coincident demand and
17 allocating more distribution costs to lighting and schools. It is easy to
18 demonstrate that Mr. Gorman is wrong on this adjustment as follows.
19 Coincidence factor is defined as the ratio of the maximum demand of a group or
20 class as a whole to the maximum demands of the components of a group or class.
21 For lighting, the maximum group demand is the same in every hour when the
22 lights are operating and equals the sum of the wattage of each light multiplied by
23 one hour. Thus for lighting the group maximum demand is the sum of the
24 individual demands and the coincidence factor is 100%. Similarly, the schools
25 operate on the same schedule and have the same weather so the class NCP is
26 likely to occur at the same hour for each school and thus the coincidence factor of
27 100% is correct. This is equivalent to saying there is no diversity in the street
28 lighting class. In other classes, there is diversity because the customers have
29 different load characteristics and hence a lower coincidence factor. Mr. Gorman
30 is incorrect to assume that the 100% coincidence factor is based on coincidence
31 with the system peak. The cost of service study has this coincidence factor

1 labeled as the class NCP coincidence factor. As a result, Mr. Gorman's
2 discussion of the coincidence with the summer peak is not relevant to the factor at
3 all. This adjustment is an error in Mr. Gorman's cost study and as a result no
4 reliance may be placed on his study.

5 **Q. WHAT CONCLUSIONS DO YOU REACH RELATED TO THE COST OF**
6 **SERVICE STUDY THAT HAS BEEN USED TO DEVELOP RATES?**

7 A. The Black & Veatch cost study is reliable for moving rates in the direction of cost
8 of service. Since there is no recommendation to set rates precisely to cost of
9 service levels, the use of estimated data does not change the order of magnitude of
10 the costs by rate schedule. Further, the changes suggested by industrial
11 interveners, aside from being self serving, are not consistent with cost causation
12 as demonstrated in the content of the report, my original testimony and in this
13 rebuttal.

14
15 *VII. Rate Design Issues*

16 **Q. DOES MR. GORMAN DISCUSS RATE DESIGN ISSUES?**

17 A. Yes. Mr. Gorman presents a chart comparing average industrial rates per kWh for
18 a selected group of investor owned utilities to the BPU rates as the basis for
19 suggesting a lower rate increase. Mr. Gorman also discusses the proposed
20 Environmental Surcharge (ESC).

21 **Q. DOES THE CHART PROVIDE ANY JUSTIFICATION FOR REDUCING**
22 **THE LEVEL OF THE RATE INCREASE PROPOSED BY THE BPU?**

23 A. No. Average rates per kWh present a limited story of rates and can be very
24 misleading related to the issue of rate increases. For example, the comparisons
25 include the pass through of tax changes that the utility is unable to control. For
26 the BPU, PILOT has increased during this period by a substantial amount.
27 Further, average rates also reflect the mix of customers for each utility that may
28 be very different. Also, the cost structure of utilities differs. This is important
29 when considering comparisons of utilities with different service areas such as
30 rural and urban. Cost structures differ based on the mix of generating assets and
31 other factors. Taken together these factors do not allow for any meaningful

1 comparison of average rates between utilities. This is particularly true when the
2 focus is on a small subset of customers such as those served on the LPS schedule.
3 Further, the customers served on this schedule are not all industrial customers. To
4 understand the relationship between utilities, it is more appropriate to use bill
5 comparisons based on specific levels of usage as opposed to average rates per
6 kWh.

7 **Q. IS THERE A BETTER WAY TO FOCUS ON THE RATE IMPACT FOR**
8 **THE LARGE CUSTOMERS?**

9 A. Yes. It is more realistic to look at the effect of the rate increase on the same
10 customers in cents per kWh. For the four BPU substation customers served under
11 Rate LPS the average cents per kWh for 2008 was 5.19 cents per kWh excluding
12 PILOT. Based on the full proposed increase for 2010, the cents per kWh equals
13 5.06 cents per kWh excluding PILOT. This is a decrease in cost of 2.5% even
14 with the full increase. It seems disingenuous for the industrial interveners to
15 complain that the rates are unaffordable and uncompetitive when despite the
16 increase proposed at 10.4 percent for these customers they will still have rates
17 below the level for 2008. For all of the other customers served under the LPS
18 rate, the results are the same. The average rate based on 2008 was 5.44 cents per
19 kWh and the 2010 rate would be 5.14 cents per kWh including the full impact of
20 the rate increase and cost reallocation. There is no reasonable basis for these
21 customers to conclude that the increase is unreasonable or that it will adversely
22 impact their business.

23 **Q. WHAT DOES MR. GORMAN PROPOSE REGARDING THE ESC?**

24 A. He proposes that the ESC not be approved based on the ability to know the costs
25 associated with environmental requirements and as a result should be included in
26 base rates. There are specific policy reasons for adopting the ESC. First, by
27 separately including these costs on a customer's bill, the customers will be able to
28 see the impact of environmental regulation directly. Second, rating agencies
29 specifically review compliance with environmental regulations to determine the
30 expected impact on capital cost and the willingness of the utility to have timely
31 recovery of these costs. In fact, they view timely cost recovery as a key ratings

1 issue. Third, the timing of the capital expenditures is also uncertain. As a result,
2 these costs might arise just after the adoption of new rates. Without the ESC there
3 would be no mechanism to recover the costs without another rate review. Given
4 that this rate review can extend for many months, this may not constitute timely
5 recovery. Fourth, these costs are beyond direct control of management since
6 compliance will be based on state and federal rules related to emissions. One
7 standard for rider recovery is that the costs are beyond management control.

8 **Q. DOES MR. GORMAN PROPOSE CHANGES TO THE ESC IF IT IS**
9 **ADOPTED?**

10 A. Yes. Mr. Gorman proposes several changes. First, he proposes to define a
11 minimum size of project for inclusion in the rider of \$10 million. As a result if
12 three power stations faced projects costing \$8 million each the costs could not be
13 included in the rider despite and aggregate impact of \$24 million. If projects were
14 truly small, it is likely that they would be cash financed. However, Mr. Gorman
15 also proposes limit the level of cash financed portions of the project to five
16 percent and a limit of no more than one percent of the rider rate impact each year.
17 In essence, Mr. Gorman seeks to limit the flexibility of the BPU with regard to
18 ESC related costs. These limits are arbitrary and have the effect of removing
19 management discretion related to the ESC without a viable reason. The BPU
20 Staff proposes certain additional modifications to the ESC that directly address
21 the concerns of Mr. Gorman but also overcome the lack of flexibility. These
22 changes define the \$10 million dollar limit in such a way that multiple projects at
23 different sites may be included if the aggregate capital cost exceeds the \$10
24 million threshold. The ESC is also changed to limit cash finance to a more
25 reasonable 25% level. To meet financial metrics related to bond ratings, providing
26 the BPU with flexibility on the issues of environmental compliance permits both
27 cost effective programs and lower costs for consumers. By limiting the cash
28 contribution, Mr. Gorman sets a precedent for more leverage just when bond
29 markets are concerned about too much leverage. Mr. Gorman also suggests that
30 the costs under the ESC be allocated to classes in the same manner as production
31 plant. This change is supported by the BPU and is incorporated in the proposed

1 BPU Staff revisions to the ESC. All other suggestions by Mr. Gorman should be
2 rejected because they are contrary to policy and to efficient and economic
3 operation of the utility.

4 **Q. DOES ANY OTHER WITNESS ADDRESS RATE DESIGN ISSUES?**

5 A. Yes. Mr. Stephens provides testimony related to the LPS rate and the proposed
6 changes to the Energy Rate Component (ERC).

7 **Q. PLEASE DISCUSS THE ISSUE RAISED BY MR. STEPHENS RELATED**
8 **TO THE DEFINITION OF BILLING DEMAND.**

9 A. The BPU proposed a change to the definition of summer billing demand by
10 expanding the on-peak period from the current definition of 10:00 AM to 8:00
11 PM to 10:00 AM to 11:00 PM. The BPU proposed change is based on a
12 statistical analysis of the high cost periods during the summer months. In
13 addition, the BPU has proposed a change in the definition of summer from May to
14 October to May through August thus shortening the summer season by two
15 months. These two changes were based on a detailed statistical analysis of BPU's
16 costs. The statistical analysis was designed to produce economically efficient
17 price signals based on grouping months and hours of like costs within the month
18 so that the highest cost hours in a group of high cost months would form the peak
19 period in the peak season. The remainder of the hours in the high cost months
20 would be off-peak hours. Statistically, this result was accomplished by
21 minimizing the variance within an economically efficient group of on-peak and
22 off-peak hours and maximizing the variance between the on-peak and off-peak
23 hours. The change to both the optimum summer season of May- August and the
24 optimum on-peak hours of 10:00 AM to 11:00 PM produced the optimal
25 combination of months and hours. The technique used to determine the optimal
26 periods has been accepted by regulators in both the United States and Canada.
27 Mr. Stephens states that the "Reduction in the peak period demand needs of the
28 system benefits all BPU customers by enabling BPU to avoid building new
29 capacity and/or procuring capacity during high cost periods." (Emphasis added.)
30 This is precisely the basis for the determination of the new on-peak period for
31 both months and hours. There is in fact a compelling reason for making this

1 change. Namely, the economically efficient on-peak period in the summer
2 months is longer than the current period. As a result, shifting load to the hours
3 just after 8:00 PM does not save costs at all. The customer benefits but does so at
4 the expense of other customers because costs do not change.

5 **Q. IS MR. STEPHENS CONCERN THAT THE INCENTIVES FOR**
6 **MANAGING THE PEAK ARE “REMOVED” BY THE CHANGE IN THE**
7 **DEFINITION OF ON-PEAK HOURS VALID?**

8 A. No. In fact, the incentive to manage peak demand during peak hours has been
9 enhanced by the emphasis on demand charges and the applicable ratchets for the
10 demand charges. Mr. Stephens takes far too narrow a review of the incentives to
11 manage demand during the peak hours. By lowering maximum demand during
12 the on-peak hours, a customer saves \$7.67 per kW in the current month and in
13 addition is able to buy more kWhs at \$0.0101 per kWh plus fuel during the
14 current month for a saving of over one cent for each such kWh. In addition, the
15 customer potentially avoids a facilities charge payment of between \$0.84 to \$2.65
16 per kW for the current month and the next 11 months. Each kW of reduction in
17 on-peak billing demand also reduces the effect of the 70% billing demand ratchet
18 during the eight winter months. Finally, when the ratchet applies in the winter,
19 the customer would also pay the higher energy charge for more hours use of
20 demand. In sum, the rate provides multiple incentives for controlling demand
21 during the on-peak period. Perhaps more importantly, by sending appropriate
22 price signals, customers are free to decide to respond or not. If a customer
23 responds to the price signals the customer benefits. If the customer decides not to
24 respond, the customer incurs higher costs to more closely match the costs the
25 BPU incurs. Thus the pricing is economically efficient. Indeed, the proposed rate
26 represents a substantial improvement in economic efficiency over the current rate
27 and does so through a market mechanism. Thus, Mr. Stephens’ concern that
28 customers have no incentive is demonstrably incorrect.

29 **Q. IS MR. STEPHENS CORRECT WHEN HE OPINES THAT “NO OTHER**
30 **ASPECT OF RATE LPS HAS A TIME OF DAY DISTINCTION FOR**
31 **CUSTOMER USE?”**

1 A. No. The energy charge has a time of day related distinction because it is billed in
2 the form of kWhs per kW of demand. The first 300 hours of demand correspond
3 roughly to the on-peak hours in each month. By reducing billing demand and
4 maintaining the same energy consumption, a customer purchases energy at a
5 lower per kWh charge that provides a time differentiated price signal without an
6 explicit time of day rate.

7 **Q. DOES MR. STEPHENS PROVIDE A BASIS IN HIS TESTIMONY FOR**
8 **APPROVAL OF THE NEW ON-PEAK HOURS?**

9 A. Yes. Mr. Stephens states that “During the summer period, the costs of production
10 or procuring in the wholesale market are most likely to be highest during on-peak
11 period. A good rate design will send proper pricing signals in order that customers
12 will operate efficiently...” (Emphasis added.) The only hours that meet this
13 requirement and provide a proper price signal are the proposed hours of 10:00
14 AM to 11:00 PM weekdays. Based on these facts, the industrial interveners
15 suggested change to the hours should be rejected and the rate as proposed in the
16 Black & Veatch report adopted as filed. It is my understanding that the BPU Staff
17 is willing to limit the definition of hours to the current 10:00 AM to 8:00 PM
18 hours for purposes of additional study. It is reasonable for the Board to provide
19 interim approval of the shorter on-peak period and allow the BPU time to prepare
20 additional analysis of the longer periods including possible customer impacts and
21 the associated critical capacity cost hours.

22 **Q. DOES MR. STEPHENS ADDRESS ANOTHER ISSUE RELATED TO THE**
23 **LPS RATE?**

24 A. Yes. Mr. Stephens would seek to reduce the demand ratchet in the winter from
25 the current level of 70% to 50% without any evidence that a 50% ratchet is
26 appropriate. In fact, this proposal is contrary to his view that price signals to
27 manage demand are appropriate. By reducing the ratchet, Mr. Stephens reduces
28 the incentive to manage summer peak demand. He does so without
29 acknowledging the value of the ratchet as a peak demand management tool.

30 **Q. WHY IS THE 70% RATCHET IMPORTANT FOR THIS RATE?**

1 A. In addition to the role that the ratchet plays in encouraging customers to manage
 2 on-peak demand in the summer, the ratchet is an important tool for equitably
 3 recovering costs from a group of customers that have very different load
 4 characteristics. For example some customers have relatively constant demands
 5 while others exhibit large swings in billing demand. The ratchet provision has no
 6 impact on the allocated costs. In fact any change in the ratchet downward forces
 7 customers with a relatively constant demand to have higher demand charges and
 8 thus subsidize the customers whose demands are more variable. The ratchet
 9 works to reduce cross subsidy within the class of customers. For example, several
 10 customers on the LPS rate have maximum and minimum monthly demand that are
 11 within plus or minus six percent of the average monthly demand. Essentially,
 12 these customers have about the same demand each month. The ratchet has no
 13 impact on these customers at all. Customers subject to the ratchet have demands
 14 that are more than 30% below the maximum demand. The ratchet provision
 15 assures that customers with highly erratic monthly demands are paying the
 16 appropriate cost of service and not being subsidized by other customers who have
 17 similar monthly demands. With a lower ratchet, there will be fewer billing
 18 demand units to cover fixed costs and results in a higher unit rate. The following
 19 table illustrates the difference for two hypothetical customers. Both of these
 20 customers have their peak demand in the same summer month consistent with the
 21 actual experience of the BPU's largest LPS customers.

22
 23
 24 **Table 4**

25 Billing Demand Units with Different Ratchets

26

	Billing Demand 70% Ratchet	Billing Demand 50% Ratchet
Customer 1- Erratic demands	141,336 kW	114,337 kW
Customer 2 -	140,977 kW	140,977 kW

Constant demands		
------------------	--	--

1

2

3

4

5

6

7

8

9

10

11

12

As this table illustrates the two customers have about the same average demand but absent the 70% ratchet, the customer with the more erratic usage pattern will pay substantially lower demand charges because the 50% ratchet reduces billing demand by over 19 percent. This reduced billing demand also means a higher demand charge as illustrated in Table 5. Table 5 assumes that the fixed cost revenue requirement for this rate class is \$1,680,000.

Table 5

Hypothetical Demand Charge for the Two Customer Rate Class

	70% Ratchet	50% Ratchet
Customer 1	141,336 kW	114,337 kW
Customer 2	140,977 kW	140,977 kW
Total kW	282,313 kW	255,314 kW
Revenue Requirement	\$1,680,000	\$1,680,000
Demand Charge	\$5.95/kW	\$6.58/kW

13

14

15

16

17

18

19

20

21

22

23

As Table 5 illustrates the difference in the ratchets causes a customer with relatively stable demand to pay \$88,815 more in demand charges with the lower ratchet. There is no justification for this difference based on cost of service and customer load characteristics. Further, only seven of the 24 LPS customers have any impact from the continuation of the current 70% ratchet and for all the customers the impact is small. The arbitrary ratchet percent change proposed by Mr. Stephens is not reasonable and works against the goal of managing summer demand and further produces unfair allocation of intraclass costs including adverse impacts on their own clients who have relatively constant monthly demands.

1 **Q. PLEASE DISCUSS MR. STEPHENS VIEWS RELATED TO THE ERC.**

2 A. Mr. Stephens expresses concerns over the inclusion of capacity charges associated
3 with purchased power expenses in the ERC. In opposing the inclusion of these
4 costs in the ERC, Mr. Stephens makes several different arguments. First, he
5 argues that these charges are not traditionally included in fuel clauses. While his
6 observation may be correct for many (but not all) investor owned utilities, his
7 argument is incorrect for municipal utilities. In fact most municipal utilities
8 include all purchased power costs in their fuel clauses. Second, there are several
9 reasons for the BPU to include these costs in the fuel clause. To the extent that
10 the BPU incurs capacity charges to acquire power to replace otherwise higher cost
11 energy production from their own units, there is a direct customer benefit. Absent
12 the ability to include capacity charges in the fuel clause, the BPU is forced to
13 decide between absorbing the capacity costs and having lower energy cost for
14 customers or generating higher cost energy and passing those costs through to
15 customers. Mr. Stephens argues that inclusion of these capacity costs provides
16 perverse incentives relative to purchased power. The exclusion of capacity costs
17 would actually create perverse incentives for the BPU. The BPU plans its system
18 to produce the lowest cost consistent with reliable service. This means that
19 purchased power contracts must meet this criteria just like the construction of
20 their own capacity. The ability to pass through capacity payments allows the
21 BPU flexibility to manage not only long term purchased power contracts but short
22 term purchases as well. Ultimately, all customers benefit from the inclusion of
23 capacity costs in the ERC. Mr. Stephens argues that the inclusion of capacity
24 costs in the purchased power expense results in shifting costs among classes. This
25 statement is incorrect. Where capacity costs are incurred to reduce fuel cost
26 expenses, for example the cost of the WAPA purchases, it is appropriate to
27 recover these costs on a per kWh basis. The recovery of capacity costs through
28 demand allocation results in low load factor customers bearing a disproportionate
29 share of the fixed costs while high load factor customers receive more of the
30 lower energy cost benefits. Mr. Stephens also discusses this issue in terms of
31 regulatory incentives. The entire discussion is directed at the regulation of

1 investor owned utilities and fails to recognize that the BPU is a municipal utility
2 that operates very differently in regard to establishing rates and recovering costs.
3 Specifically, the BPU has no shareholder returns that can be used to absorb
4 unrecovered costs as is true for an investor owned utility. The only way for the
5 BPU to deal with “regulatory lag” would be for the municipality to contribute
6 cash to meet the expenses or to raise rates on little or no notice. That is why the
7 BPU has a Rate Plan for multiple years and adjustment clauses to avoid under
8 recovery of costs and the rating agencies recognize the importance of this
9 flexibility in their ratings. They simply have no other source of cash for
10 operation. Ultimately all of the costs incurred to serve customers must pass
11 through to those customers if the utility is to avoid financial ratings down grade or
12 inadequate cash for operations. Neither of those outcomes is acceptable for the
13 BPU. Finally, Mr. Stephens opines that there are offsets to these purchased
14 capacity costs included in base rates such as off system sales margins. This
15 statement is incorrect. The BPU essentially uses all of its low cost capacity for its
16 own load. If it makes off-system sales it is because its own customers are using
17 less power. The level of margin in BPU non-fuel base rates is higher than the
18 level of margin in off-system sales. The end result is that off-system sales result
19 in lower cash flows than the utility would normally expect. Since the BPU
20 operates on a cash basis, the utility financial metrics are eroded from opportunity
21 sales. With respect to contract sales out BPU owned generation, those contract
22 sales produce cash flow equal to costs. There is no offset to capacity costs for
23 opportunity purchases without recovery through the ERC. Mr. Stephens’ position
24 should be rejected and the ERC approved as filed.

25 **Q. DOES MR. STEPHENS PROPOSE A CHANGE TO THE ERC IF IT IS**
26 **APPROVED TO RECOVER PURCHASED POWER CAPACITY AND**
27 **TRANSMISSION COSTS?**

28 A. Yes. Mr. Stephens recommends the inclusion of off-system sales margin in the
29 ERC. As I have discussed above, the incremental sales margins are only possible
30 if the energy is not sold to retail customers and the net result of crediting these
31 margins to the ERC would be reduced cash flow contrary to the goal of meeting

1 certain financial metrics. This proposal should be rejected and the ERC going
2 forward from January of 2011 should be the ERC as revised by the BPU Staff and
3 discussed by Mr. Elliot.

4 **Q. DOES THE BPU HAVE ANY INCENTIVE TO PROCURE EXCESS**
5 **CAPACITY FOR THE PURPOSE OF ENHANCING ITS “BOTTOM**
6 **LINE” AS MR. STEPHENS SUGGESTS?**

7 A. No. This is another case where Mr. Stephens employs testimony rhetoric from
8 investor owned utility regulation to address municipal utility outcomes. The BPU
9 does not have earnings like investor owned utilities. The BPU operates on a cash
10 basis and retains cash for two purposes: 1) having adequate days of operating
11 cash on hand to meet the minimum expectations of rating agencies and
12 bondholders and 2) having extra cash to reinvest in the system to avoid excess
13 leverage and assure adequate bond coverage. Mr. Stephens is simply wrong about
14 the ERC incentives. As a result, all of his proposed changes to the ERC should be
15 rejected.

16 *VIII. Summary and Conclusions*

17
18 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS RELATED TO**
19 **THE PROPOSED RATE PLAN.**

20 A. The BPU proposed Rate Plan represents a reasonable rate plan designed to meet
21 the minimum financial metrics required to retain the current favorable bond
22 ratings. The assumptions that support the plan have been carefully considered by
23 the BPU Staff and they have been reassessed based on the discussion and
24 testimony of the Industrial Interveners. As part of the process, the BPU Staff and
25 B&V have reanalyzed all aspects of the proposed Rate Plan. As part of that
26 review, the BPU Staff recognizes that there is always some probability that
27 circumstances may work to create either more revenue or less cost so that the plan
28 is able to exceed the required financial metrics. In that unlikely event, the BPU
29 does not propose to retain excess cash but rather to credit the excess cash against
30 the level of rate increase in later periods. Under this proposal, the BPU Staff
31 would reduce the proposed increase to reflect the better than expected cash
32 position. Since the Rate Plan represents the maximum increase that customers

1 would face without another rate proposal, the approval of the Rate Plan sets a cap
2 on rates but approval below the cap would not require another rate filing. As a
3 result, I recommend that the Board approve the proposed Rate Plan. I also
4 recommend that the Board approve the changes to the ERC and ESC as discussed
5 in the BPU Staff testimony. Both of these proposals are reasonable and reflect the
6 appropriate process for a municipal utility to have timely and efficient cost
7 recovery. I also recommend that the Board approve the cost of service study and
8 results as filed by B&V. Finally, I recommend that the Board approve the
9 proposed rate changes for each rate schedule. This includes the new definitions of
10 the seasons and the allocation based on the cost of service study for 2010.

11 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

12 A. Yes.

13

14

15

16