COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

The Application of the Fuel Adjustment Clause of Kentucky Power Company from November 1, 2013 Through April 30, 2014	**)) Case No. 2014-00225)**

REBUTTAL TESTIMONY OF

KELLY D. PEARCE

ON BEHALF OF KENTUCKY POWER COMPANY

November 5, 2014

VERIFICATION

The undersigned, Kelly D. Pearce, being duly sworn, deposes and says he is the Director Contract and Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Kelly D. Pearce

STATE OF OHIO	)	
	)	Case No. 2014-00225
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kelly D. Pearce, this the 3 day of November 2014.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Kristina L. Woods
Notary Public, State of Ohio
My Commission Expires 03-07-2016

My Commission Expires: 3-7-16

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
KELLY D. PEARCE ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelly D. Pearce, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Director of Contracts and Analysis. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the electric operating companies of the American Electric Power System, one of which is Kentucky Power Company ("Kentucky Power" or "Company").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University in 1984. I received Master of Science and Doctor of Philosophy degrees in Nuclear Engineering from the University of Michigan in 1986 and 1991 respectively. I received a Master of Science in Industrial Administration degree from Carnegie Mellon University in 1994.

From 1986 to 1988 I worked for a subsidiary of Olin Corporation. From 1991 to 1996 I worked for the United States Department of Energy within the Office of Fossil Energy.

My responsibilities included serving as a Contracting Officer's Representative in the oversight and administration of government-funded research of advanced generation and environmental remediation technologies and projects. I also supported strategic studies for deployment and commercialization of these technologies as well as administration and support of Government research and development solicitations. I was promoted twice during this time.

In 1996 I joined AEPSC as a Rate Consultant I in Regulatory Services. In 2001, I was promoted to Senior Regulatory Consultant. My responsibilities included preparation of class cost of service studies and rate design for AEP operating companies and the preparation of special contracts and regulated pricing for retail customers. In 2003 I transferred to Commercial Operations as Manager of Cost Recovery Analysis. In 2007 I was promoted to Director of Commercial Analysis. During this period, I was responsible for analyzing the financial impacts of Commercial Operations-related activities. I also supported settlement of AEP's generation pooling agreements among the operating companies. In 2010 I transferred to Regulatory Services in my current position.

I am a registered Professional Engineer in Ohio and West Virginia.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My group is responsible for performing financial and other analyses concerning AEP's generation resources and load obligations, settlement support for AEP's operating companies, including that associated with certain affiliate agreements and the PJM regional transmission organization, and regulatory support in areas that relate to commercial operations. In addition, my group is responsible for AEP's wholesale formula rate agreements.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No. I have, however, participated from time-to-time in informal conferences, particularly with respect to the AEP Pool, PJM and market settlement issues, with the Commission Staff and representatives of the Intervenors. My participation in those informal conferences was on behalf of the Company.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have testified before the Public Utilities Commission of Ohio, the Virginia State Corporation Commission and the Indiana Utility Regulatory Commission. I have also submitted testimony to the Federal Energy Regulatory Commission. My testimony in all of these proceedings was on behalf of operating companies that are affiliates of Kentucky Power.

II. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut several of the claims of Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky ("KIUC/AG") Witnesses Kollen and Hayet regarding the Company's allocation of fuel cost between internal load and off system sales during the review period. Contrary to the claims of Messrs. Kollen and Hayet, the Company's fuel costs are allocated in a just and reasonable manner. The Company has maintained a consistent methodology for decades that results in an allocation that is more appropriate than anything offered by these witnesses. Furthermore, it appears both Messrs. Kollen and Hayet consider the fuel cost allocation to be a process that is independent from the dispatch of the units, which is a fundamentally flawed assertion. By incorporating the dispatch considerations and parameters, the Company's cost allocation method is not only just and reasonable, but produces a beneficial and fair result for the Company and its customers, that is consistent with regulatory practices.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The Company has been performing its fuel cost allocation between internal load and off system sales ("OSS") consistently for decades and applied that allocation across multiple state and Federal jurisdictions without challenge. This method is consistent with the development of the $15.3 million OSS credit currently in base rates.

The Company's method of allocation includes consideration of the dispatch parameters of the Company's units which results in a more appropriate allocation of fuel cost than the method proposed by the KIUC/AG witnesses. It is consistent with FERC rulings on assignment of incremental costs to OSS as discussed by Company Witness Allen.

The KIUC/AG method could introduce harm to customers in that it would potentially require such a conservative dispatch into the PJM market that overall OSS margins may be reduced and additional power purchases may be required just to serve the load of the Company.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

Exhibit KDP-1 – AEP Interconnection Agreement Excerpt

Exhibit KDP-2 – Illustrative Cost Allocation

Exhibit KDP-3 – *PJM Manual 15: Cost Development Guidelines* Excerpt

Exhibit KDP-4 – PJM eMKT Screenshot for Mitchell 2

Exhibit KDP-5 – Estimated Jan-April 2014 Impact without Mitchell

III. SETTLEMENT PROCESS

Q. ARE YOU FAMILIAR WITH STATEMENTS MADE BY THE KIUC/AG WITNESSES HAYET AND KOLLEN REGARDING THE COMPANY'S SETTLEMENT PROCESS?

A. Yes. Both Messrs. Hayet and Kollen take the position that the Company's cost allocation resulting from its settlement process was improper or unreasonable (Kollen, page 6; Hayet, page 3). Such claims are not correct in either a historical context or based on how the allocation is currently performed.

Q. ARE YOU FAMILIAR WITH HOW THE COMPANY HAS HISTORICALLY PERFORMED ITS SETTLEMENT PROCESS?

A. Yes I am. I have been personally involved with the settlement process for more than a decade, and the settlement process has been performed in a consistent manner throughout that period. Furthermore, based on my review of Company records, the settlement process occurred in a consistent manner for at least a decade before my involvement.

Q. DID THE COMPANY HAVE A JOINT SETTLEMENT WITH ANY OTHER COMPANIES DURING ANY PORTION OF THE REVIEW PERIOD?

A. Yes. The AEP operating companies in the AEP East zone, including Kentucky Power, were members of the AEP Interconnection ("Pool") Agreement until January 1, 2014. Under the Pool Agreement, the AEP operating companies performed joint dispatch and joint settlement, and the non-incremental costs known as no load costs were assigned to internal load as they are today.

Q. WHAT IS THE CONNECTION BETWEEN DISPATCH AND SETTLEMENT?

A. They are inseparable. While Mr. Kollen appears to recognize "the principle of cost causation" as evidenced by his statement on page 4, line 13 of his testimony, he undermines this statement by also claiming that no load costs are not relevant for fuel cost allocation (Kollen, page 10). Similarly, Mr. Hayet attempts to make arguments that unit dispatch and fuel cost allocation "…are two completely different matters." (Hayet, page 8). Significantly, neither witness appears to provide a rationale or basis for his assertion, and their claims are inaccurate. Cost causation requires the cost reconstruction to follow the dispatch. Dispatch is what causes the fuel cost to be incurred in the first place, and so ignoring it in the subsequent fuel allocation during cost reconstruction is fundamentally flawed. Similarly in this case, to ignore certain dispatch parameters, such as the no load cost of the units, is inappropriate and inconsistent with the concept of cost causation.

Q. PLEASE EXPLAIN HOW DISPATCH AND COST RECONSTRUCTION WERE PERFORMED UNDER THE AEP POOL.

A. Under the AEP Pool Agreement, the dispatch of the AEP operating companies' units was always performed first and foremost to serve internal customers' load, including that of retail customers and full-requirements wholesale customers.

Prior to AEP joining PJM, AEP dispatched all of the operating companies' units in a combined manner to serve the sum total load of all of the companies. Dispatch of all AEP units was performed on an economic basis and without regard to the ownership of any of the units. In addition, AEP would monitor the markets for potential economic purchases and economic OSS. The post-dispatch cost reconstruction to allocate cost to OSS was done consistent with this dispatch commitment to serve internal load first. Incremental dispatch is then considered to determine OSS and the most expensive incremental generation is applied to OSS.

The only changes made to dispatch and unit commitment resulting from AEP joining PJM is that the load of the AEP operating companies, including Kentucky Power, are submitted to PJM on a day-ahead basis and PJM controls the dispatch. But these changes in no way affect the dispatch commitment to serve internal load first and the most expensive incremental generation is allocated to OSS.

Q. PLEASE DESCRIBE COST RECONSTRUCTION.

A. The basics of cost reconstruction are as follows: For any hour in which an OSS is made, the most expensive megawatt-hour (MWh) produced out of all units on-line is identified for that hour. This designated MWh is the source for the OSS under the principle that this MWh was dispatched "last" as the most expensive MWh and therefore should be assigned to OSS. Stating that the most expensive MWh is dispatched "last" follows from the premise that the units are dispatched on an economic basis starting with the least expensive energy and then dispatched incrementally with each incremental MWh being the same or more expensive than the MWh that preceded it – basically just moving up the supply curve.

The "out-of-pocket" cost for this MWh of OSS is the difference in the cost of the unit at the actual dispatch level and the cost of the unit at one MWh less than the dispatch level.

For example, if a unit ran and produced 400 MWh in a given hour at a total fuel cost of $11,000, and the cost of producing 399 MWh is $10,973, then the incremental cost of the last MWh produced was $27 ($11,000 - $10,973). The settlement system compares the $27 dollar incremental cost from that unit to the similar incremental cost for every unit that was above its minimum. The absolute highest value from amongst all the units is the cost-basis for the OSS. The system performs this same determination for each and every MWh of OSS on a MWh-by-MWh basis until the highest cost MWhs across all of the units have been assigned to OSS for that hour. This ensures that the units with the highest incremental cost are the units from which costs are assigned to OSS including the Big Sandy, Mitchell and Rockport units. Power purchases are also “stacked” in the supply curve and are similarly allocated along with generation either to OSS or internal load on an economic basis.

Q. WHAT IS THE RELEVANCE OF THE MINIMUM MEGAWATT VALUES?

A. The unit minimums megawatt values are the values below which the units cannot be dispatched in a sustainable manner, at least for an extended period. This is why unit-by-unit allocation below the minimums is not performed.

Q. HOW DO THE NO LOAD COST FIT INTO THIS METHODOLOGY?

A. No load costs are not incremental and are incurred regardless of whether any off system sales are made from a unit. Since the Company allocates cost to OSS consistent with the dispatch of units and historic cost reconstruction practices using a “top down” approach, no load cost remain with internal load. This no load treatment is reasonable and consistent with the premise that units are first made available and dispatched to serve internal load and consequently always serve some portion of internal load whenever they are on-line.

Q. IS THIS ALLOCATION METHODOLOGY CONSISTENT WITH THE FORMER AEP POOL AGREEMENT?

A. Yes it is. As provided in Exhibit KDP-1 Article 7.5 of the AEP Pool Agreement, “*Settlement for Power Sales to Foreign Companies*” describes this process. Settlement was performed as described under that article as I have just outlined it, and I am unaware of any past challenges or disputes regarding the methodology's consistency with the AEP Pool Agreement which was in place for over 60 years.

Q. WAS THIS PRACTICE CONTINUED ONCE THE AEP POOL AGREEMENT WAS TERMINATED?

A. Yes it was. As of January 1, 2014 the cost reconstruction of the Company's generation is now performed on a "stand alone" basis. Without the AEP Pool, the settlement is now only for Kentucky Power's units and Kentucky Power's load. The same methodology was also retained for all the other former member companies of the AEP Pool Agreement, excluding Ohio Power, which corporately separated and no longer owns generation.

Q. WHY IS IT APPROPRIATE FOR KENTUCKY POWER TO CONTINUE THIS PRACTICE FOLLOWING THE TERMINATION OF THE AEP POOL AGREEMENT?

A. The reasons remain the same. Kentucky Power's units are first made available and dispatched to serve the internal load of the Company. In fact, since Kentucky Power now has no "back-up" in the form of cost-based generation from the other AEP operating companies when its own units are not available, this method provides operational benefits. As I will explain later in this testimony, it allows the units to be offered into the PJM market in the most economically efficient way possible to maximize their value, for customers and the Company. This maximizes their availability to serve internal customers' load.

Q. IS MR. KOLLEN'S DESCRIPTION OF THE COMPANY'S COST ALLOCATION METHOD ACCURATE?

A. No. Mr. Kollen, on pages 7 and 8 of his testimony describes a "bottom up" approach of allocating costs first to internal load. The Company, in actuality as I have just described, performs a "top down" approach of allocating the most expensive incremental generation on a MWh-by-MWh to OSS. A simplified, illustrative representation of the Company's method of allocation is provided in Exhibit KDP-2.

IV. NO LOAD COST

Q. WHAT IS MR. KOLLEN'S POSITION ON THE ALLOCATION OF NO LOAD COST?

A. Mr. Kollen takes the position that some portion of no load costs should be allocated to all OSS (Kollen, page 10-11).

Q. WOULD SUCH AN APPROACH BE CONSISTENT WTH THE ALLOCATION METHODOLOGY HISTORICALLY USED BY KENTUCKY POWER?

A. Certainly not. Such an approach would be a material departure from the manner in which the Company has been doing business for years and filing its fuel adjustment clause reports with the Commission, and, as described in more detail by Company Witness Wohnhas, is inconsistent with the development of the test year OSS margin that was credited against, and accordingly lowered, base rates.

Q. IS MESSRS. KOLLEN'S AND HAYET'S APPROACH APPROPRIATE?

A. No. No load cost are somewhat analogous to a car that is turned on and idling. The car is incurring gasoline consumption expense but it is not incurring gasoline expense to travel – it is however ready and available to travel. To be clear, I agree with Mr. Hayet that the Company's generation units cannot sit "idle" without producing at least some MWhs. However, this engineering constraint on power plants does not preclude the use of no load cost in modeling solutions for economic dispatch. Recognizing the engineering constraint can and is done simply by constraining each unit's output to at least its minimum megawatt (MW) value the unit can sustain without prolonged harm or other operational issues.

Q. IS THE USE OF NO LOAD COST IN DEVELOPMENT OF DISPATCH SUPPLY CURVES UNIQUE TO AEP?

A. No. The dispatch process I described is not an AEP-only construct. With respect to dispatch, PJM, an organization that includes many utilities, specifically requires that no load cost are included for its cost development and dispatch activities as evidenced by its inclusion in PJM costing guidelines. Provided as Exhibit KDP-3 is an excerpt from *PJM Manual 15: Cost Development Guidelines*. PJM clearly recognizes such costs and requires their development for fossil units, as evidenced in Section 2.5 of the exhibit.

Q. HAS FERC ADDRESSED THE ALLOCATION OF INCREMENTAL COSTS TO OFF-SYSTEM SALES?

A. PJM manuals are not filed and approved by FERC. What the PJM manual shows is that no load costs are defined as non-incremental costs. As discussed in detail in the testimony of Company witness Allen, the assignment to OSS of only the incremental costs incurred to make the off-system sales is in compliance with FERC orders.

Q. DO YOU HAVE AN EXHIBIT THAT ILLUSTRATES THE PJM DISPATCH PROCESS?

A. Yes I do. Exhibit KDP-4 provides an actual screenshot of PJM's eMKT system. To make its daily offers, the Company fills in the no load cost as shown and circled in the middle left of the exhibit. This is the cost of the unit when it is on line that is not attributed to any MWh production from the unit. The incremental $/MWh offers are provided for each block of generation as shown in the lower right of Exhibit KDP-4. This is the information submitted to PJM to perform its dispatch solution. It is important to note that each additional block offer into PJM has a higher $/MWh cost. In other words, as shown in the exhibit, the block of energy between 325 MWs and 395 MWs will be a higher $/MWh value than the lower blocks. Since the dollar per MWh of the blocks increase as more MWhs from this unit are dispatched, it will be these *higher cost $/MWhs* that are allocated to OSS, whenever an OSS is made.

Q. ARE THERE ANY REQUIREMENTS ON OFFERING THE COMPANY'S GENERATION UNITS INTO THE PJM MARKET?

A. Yes. PJM requires that all units that are recognized as PJM capacity resources must be offered into the PJM market whenever they are available.

Q. WHAT ARE THE IMPLICATIONS IF NO LOAD COST WERE ALLOCATED TO OSS?

A. As I previously mentioned, the dispatch and settlement processes are related by the very cost causation principles that Mr. Kollen espouses to. Using my previous example of a unit with a $27/MWh cost as the highest cost MWh, and assume that the OSS revenue associated with that MWh was $29, then the resulting OSS margin is $2 ($29 - $27), under current dispatch and cost allocation methodology. This OSS margin, under past practice for the Company, would then be equitably shared between customers and the Company. Everyone benefits under this scenario. If, however a change is made to allocate no load costs to the cost of OSS then there is an economic disincentive for the Company to make the OSS. To illustrate this disincentive assume $3 of no load cost is allocated to OSS, then the OSS margin becomes a $1 *loss* ($29 revenue less $30 fuel cost basis). Therefore, the Company is incented not to make the OSS, to the ultimate disadvantage of the customer. The $2 of margin above variable cost would be lost absent the sale. Under the sharing mechanism that the Company had in place for many years, this would result in a $1.2 increase in cost to internal load customers. Further, if the Company is disincented from making off-system sales because no-load costs are allocated to OSS, the Company may not achieve the OSS margins credited against base rates, ultimately requiring the customers to make up the difference.

Q. IS IT REALISTIC TO ASSUME OSS WILL BE REDUCED IF NO LOAD COSTS ARE ALLOCATED TO OSS?

A. Yes. If the dispatch and cost allocation or reconstruction are not aligned, then the Company will need to take this misalignment into consideration when it is doing its upfront dispatch activities. The result would effectively be a signal to the Company not to optimize OSS, but rather take a much different approach in its unit offerings. Under basic economic theory, any time a manufacturer of a product, be it electricity or widgets, can sell one more unit of its product along its supply curve at a price which covers more than the *incremental* cost to produce that unit, it should do so.

However, under the KIUC/AG methodology, the Company would effectively be directed to factor a non-incremental costs into its decision to make an off-system sale. This would result in a number of hours in which a sale that was made using incremental costs would not now be made. The result is the Company's customers and the Company would lose the benefit from OSS, because rather than receiving a credit that lowers total cost, there is a *cost increase* in terms of lost opportunity cost.

V. KIUC/AG PROPOSED METHODOLOGY

Q. ARE YOU FAMILIAR WITH HOW KIUC/AG HAVE PROPOSED TO ALLOCATE FUEL COST BETWEEN INTERNAL LOAD AND OSS?

A. Yes I am, based upon the work papers that they provided.

Q. CAN YOU PLEASE DESCRIBE IT?

A. KIUC/AG Witness Hayet takes the hourly fuel cost of each unit in terms of a dollar per MWh total cost and allocates to internal load the lowest cost units up to the internal load and then any remaining cost is allocated to OSS. This is a "bottom up" approach as opposed to the Company's practice of assigning from the top of the stack down on an incremental basis.

Q. DO YOU AGREE WITH THIS APPROACH?

A. No I do not. Such an approach allows for cost to be allocated in a manner that does not represent the dispatch pricing and does not consider the realities of the way units dispatch. Such an allocation method, while simple, introduces at least two issues.

Q. WHAT IS THE FIRST ISSUE WITH THE KIUC/AG APPROACH?

A. The first issue is the concern that the allocation of total cost hour-by-hour does not represent the actual PJM offers and settlement process. When units are offered into PJM, a minimum run time is provided. Many of the supercritical units are offered in for a minimum of the entire 24-hour period of the next day. When PJM solves its solution for awards to generation, it will ensure that the generator gets at least its total no load and incremental generation over the entire daily offer period, 24 hours or otherwise. However, *PJM does not dispatch the units such that it ensures recovery of both no load cost and the incremental cost in any given hour.*

Q. COULD THE COMPANY JUST TURN THE UNITS OFF WHEN THEY DON'T COVER BOTH THEIR INCREMENTAL AND NO LOAD COST IN CERTAIN HOURS?

A. No, even though that would be rational from a purely economic standpoint, it is not possible from a practical standpoint. Other factors must be considered. For instance, the Company's units all have start times that are several hours in duration as shown below:

Unit	Cold Startup Duration (Hours)	Warm Startup Duration (Hours)	Hot Startup Duration (Hours)
Big Sandy 1	20	13	5
Big Sandy 2	18	15	11
Mitchell 1	19	13	6
Mitchell 2	19	13	6
Rockport 1	29	26	10
Rockport 2	29	26	10

The units being on in the off-peak hours -- even if they are not clearing all of their cost during those hours -- is what enables them to be available in the on-peak period.

The KUIC/AG proposal inherently results in a unit allocation that does not match the actual dispatch parameters, resulting in "upside down" economics by forcing units to OSS when they are "out of the money" and selectively assigning the units to internal load only for certain hours when they are in the money. To be clear, no one disputes that the Company's customers have the "first call" on the generation from these units. But with that right also lies the obligation to pay the no load cost and then let the incremental cost be the determination in the dispatch of the units between their minimums and maximums and then equitably allocate this incremental margin.

Q. WHAT IS YOUR SECOND CONCERN WITH THE KIUC/AG METHOD?

A. The second concern is the resulting wear and tear on the units if they were being constantly stopped and restarted as incented by their proposed methodology. Kentucky Power's units are base load units. To actually turn base load units on and off frequently would create thermal stresses on the units, more start-up costs, more auxiliary power usage, more labor costs, reduction in component life and the additional risk of potential unit trips during start-up. This type of operation would therefore substantially increase the operations and maintenance ("O&M") cost of the units. It is much better to bring the units down to their minimums and remain on line rather than to shut down and restart units. It is the alignment of cost allocation and dispatch under the Company's practice that fosters the efficient operation of base load units, resulting in lower expenses that benefit customers.

The KIUC/AG method inherently assumes that the units can be flipped on and off like light switches. It seems somewhat contradictory for the KIUC/AG witnesses to be so concerned with no load cost being "theoretical" in nature, when at least there appears to be no dispute that they are used in the actual PJM dispatch processes, and yet give no acknowledgement to the operational realities of how quickly units can be started and stopped.

VI. OTHER UTILITIES

Q. ARE YOU FAMILIAR WITH KIUC/AG WITNESS KOLLEN'S TESTIMONY REGARDING THE METHODS USED BY OTHER KENTUCKY UTILITIES AND COOPERATIVES?

A. Yes. Mr. Kollen describes, based at least in part on data request responses by those utilities, how various utilities and cooperatives in the Commonwealth perform there allocation of fuel cost between internal load and OSS. Mr. Kollen then argues that Kentucky Power must be doing this allocation incorrectly since other utilities do it different than the Company.

Q. DO ANY OTHER AEP AFFILIATED COMPANY'S ALLOCATE NO LOAD COST IN A SIMILAR FASHIO TO THE COMPANY?

A. Yes. I have already made mention of the other former AEP Pool Agreement member companies, which used this same method before and after the termination of the AEP Pool Agreement. In addition, the former Central and South West ("CSW") operating companies, which included four separate operating companies operating in portions of Arkansas, Louisiana, Oklahoma and Texas, were using a similar methodology when it comes to no load cost allocation both before and after CSW's merger with AEP in 2000. Specifically, these CSW operating companies performed an incremental cost allocation to OSS similar to the method used in the east. No load costs were and are assigned to internal load for the former CSW companies as they are for Kentucky Power and its eastern affiliates.

Q. WHAT ABOUT OTHER UTILITIES WITHIN THE COMMONWEALTH OF KENTUCKY?

A. LG&E and KU use an incremental methodology for allocation of resources to OSS. LG&E and KU use their "After-The-Fact" ("AFB") model to determine the joint dispatch savings and then payments are made between LG&E and KU that "split-the-difference". The LG&E/KU model determines the incremental cost of the additional dispatch -- above that needed to serve internal load -- to make off system sales. It is then this incremental cost that is allocated to OSS. LG&E and KU "stack" incremental, *not* total average, cost of each generator in each hour for their off system sales cost allocation. As a result, the LG&E/KU computations appropriately consider the dispatch of their system for purposes of identifying which resources supplied off system sales on an incremental basis. This means, based upon my review and current understanding of the LG&E and KU allocation method, that it is not far afield from the Company's method.

VII. ROCKPORT CONSIDERATIONS

Q. DO YOU AGREE WITH MR. KOLLEN'S CHARACTERIZATION OF ROCKPORT PURCHASES AS IT RELATES TO THE COMPANY'S ALLOCATION OF THESE PURCHASES?

A. No. Mr. Kollen simply provides a monthly billing invoice for the Company's 15% purchase from these units which includes as a line item the total fuel cost for the month (Exhibit LK-2). Mr. Kollen then argues that since these invoices do not segregate no load fuel cost that Kentucky Power is somehow "marking up" Rockport fuel allocated to native load (Kollen page 11, line 22 through page 12, line 6).

In regards to the Rockport invoice, there is not much difference between such an invoice for the Company's fuel expense at Rockport and a fuel invoice the Company could receive for fuel acquired for its own plants, the latter of which would also be expensed once it is consumed in the boiler. The Company obtains its portion of the Rockport units from affiliates. The actual cost data for these units is developed and offered into the PJM market via the same methods and by the very same group within AEP that dispatches the Company's own units. As a result, the entire heat input and all of the costing information is just as known for Rockport as it is for the Company's other units.

VIII. KIUC/AG'S QUANTIFICATIONS

Q. DO YOU HAVE ANY COMMENTS REGARDING THE VALUES PRESENTED BY MR. KOLLEN AND MR. HAYET?

A. Yes I do. Mr. Kollen presents a table on page 14 which he shows as support for the Company's allocation method somehow being improper. For a fairer representation, the table below shows that once the no load costs are properly removed from the total fuel costs, the remaining fuel expense values demonstrate that the most expensive incremental cost has been assigned to OSS.

TOTAL FUEL COST EXCL. NO LOAD COST ($/MWH)	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014
Fuel Cost $ Per MWH For All Generating Plants	21.68	22.33	20.46	20.34
Fuel Cost $ Per MWH Allocated to Off-System Sales	24.42	25.95	24.39	22.36
Fuel Cost $ Per MWH Allocated to Native Load	20.15	19.92	17.92	17.92

As discussed by Company Witness Allen, whether or not the OSS costs are above or below the average system cost is not, in and of itself, evidence as to the appropriateness of the cost allocation methodology since such incremental costs may be above or below the system average. However, within the confines of the incremental dispatch, the Company's methodology allocates higher cost to OSS and thereby reduces the incremental cost allocated to internal load customers.

IX. MITCHELL TRANSFER CASE

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KOLLEN'S TESTIMONY PERTAINING TO CASE NO. 2012-00578, THE "MITCHELL TRANSFER CASE"?

A. I do. On page 5 of Mr. Kollen's testimony, he refers to the fuel cost savings referenced in paragraph 2 of the stipulation and settlement in that proceeding. That value, based on a simplified calculation between the Mitchell and Big Sandy 2 fuel cost, was $2.50/MWh or $16.75 million annually based on 2012. Mr. Kollen claims that such fuel cost savings was an incorrect claim on behalf of the Company.

However, consistent with the Stipulation, Mitchell fuel costs have been lower than that of Big Sandy 2 as described by Company witness Wohnhas. Furthermore, while adding Mitchell did increase the Company's no load fuel cost, it also provided significant fuel cost savings during the fuel audit period. As evidence of this, provided in Exhibit KDP-5 is an estimate of the fuel cost the Company's internal load customers would have incurred had Kentucky Power not had Mitchell during the four month period from January through April 2014. As demonstrated in this exhibit, Kentucky Power's customers would have incurred approximately $9.9 million in additional costs (as compared to the costs recovered via the FAC in the same period) had the Company not had both Mitchell and Big Sandy Unit 2 in its portfolio. The resulting average fuel cost savings was $3.90/MWh, which *exceeds* the $2.50/MWh value referenced in Paragraph 2 of the Stipulation and Settlement Agreement. This analysis shows that without Mitchell, even though the Company would have avoided the no load cost associated with Mitchell, it would have instead incurred significant additional costs to meet its customers' needs.

In addition, over the long run customers will benefit from the total fuel cost savings of Mitchell over Big Sandy in that the Mitchell transfer is what will enable the elimination of the Big Sandy no load fuel cost. Assuming the Company returns to OSS sharing comparable to historic mechanisms, the Company's customers will get the benefit of the lower Mitchell fuel cost through both internal load cost reduction and lower fuel cost allocated to OSS margins, which will create larger customer credits.

X. PRE-2014 COST ALLOCATION

Q. DO YOU HAVE ANY COMMENTS ON KIUC/AG WITNESSES KOLLEN AND HAYET'S TESTIMONY REGARDING YEARS PRIOR TO 2014?

A. Yes. Looking back prior to 2014, even the KIUC/AG witnesses acknowledge that including the impact of the AEP Pool Agreement creates additional complexity for an already complex subject. If it is KIUC/AG's position that more of the fuel cost of the Company's units should have been allocated to OSS during this pre-2014 period, all but a Member Load Ratio (MLR) share of that increased OSS costs would have had to have been reimbursed by the Company's affiliates. Similarly, this would also mean that all of those same affiliates would have needed to allocate more of their own units' fuel cost to OSS, and an MLR share of that would have been born by the Company. This illustrates just some of the difficulties in attempting to retroactively determine and impose a different mechanism then was actually in practice, particularly during the period in which the AEP Pool Agreement was in place

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

COMPOSITE COPY

INTERCONNECTION AGREEMENT

BETWEEN

APPALACHIAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY *

INDIANA & MICHIGAN ELECTRIC COMPANY

AND WITH

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

AS AGENT

Dated: July 6, 1951, as modified and supplemented by:

Modification No. 1, August 1, 1951
Modification No. 2, September 20, 1962
Modification No. 3, April 1, 1975
Supplement No. 1 to
Modification No. 3, August 1, 1979
Supplement No. 2 to
Modification No. 3, August 27, 1979
Modification No. 4, November 1, 1980 *
Compliance Filing (FERC ordered), Opinion 266,
Docket Nos. ER84-579-006 and EL86-10-001

* Pursuant to Modification No. 4 the terms "Member" and "Members", whenever said terms appear in the 1951 Agreement, shall, on and after the time when Modification No. 4 shall become effective, include Columbus Company.

cost, i.e., fuel expense and an appropriate portion of maintenance expense of generating facilities that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the System. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of such generating facilities shall be determined and agreed upon by the Operating Committee.

Settlement for Power Sales to Foreign Companies

7.5 Settlement by the Members through the SYSTEM ACCOUNT for electric power and energy sales to Foreign Companies shall be governed by the principle that the difference between the amount charged a Foreign Company for the power and energy supplied under such a sale and the production expenses, i.e., out-of-pocket costs incurred by the System in making such supply, shall be shared by the Members in proportion to the respective MEMBER LOAD RATIOS. Electric Power and energy for such sales shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying power to the System under arrangements with Foreign Companies.

(The following illustrates the application of the principles and procedures for effecting such settlements:

It is assumed that Indiana Company has sold a block of energy at a rate of 4.00 mills per kilowatt-hour which has been supplied by carrying a block of load that would not otherwise be carried at Philo Station of Ohio Company, the out-of-pocket cost incurred by Ohio Company being 3.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy would be at the following rates: (1) charge

Indiana Company at a rate per kilowatt-hour equal to the sum of 3.00 mills plus the product of 1.00 mill times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS, (2) pay Ohio company at a rate per kilowatt-hour equal to the sum of 3.00 mills and the product of 1.00 mill times Ohio Company's MEMBER LOAD RATIO, and (3) pay Appalachian Company at a rate per kilowatt-hour equal to the product of 1.00 mill times Appalachian Company's MEMBER LOAD RATIO.)

Settlement For Power and Energy Received Under
<u>Interchange Arrangements With Foreign Companies</u>

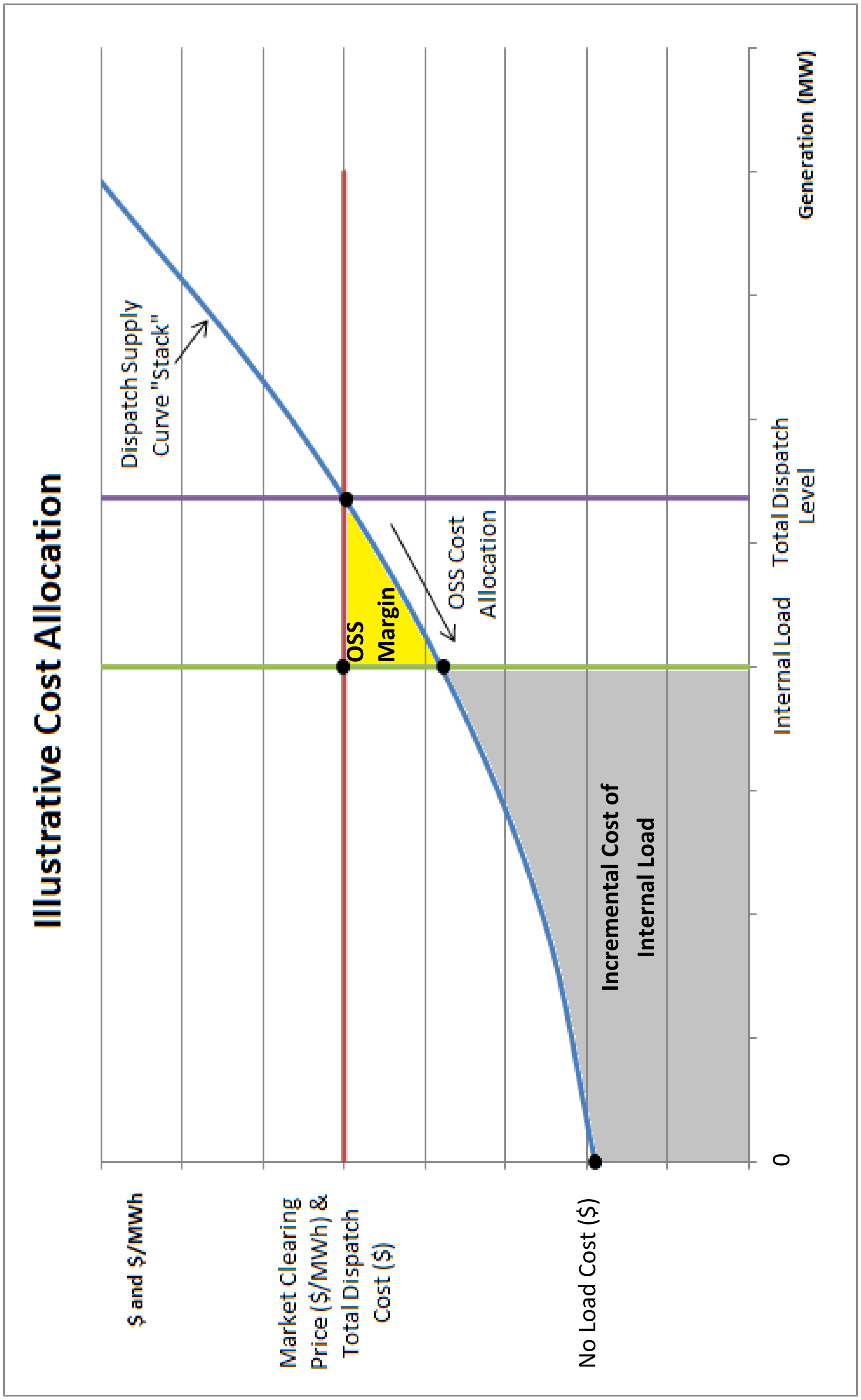
Power and Energy Received other
<u>than Interchange Economy Energy</u>

7.6 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy received, other than INTERCHANGE ECONOMY ENERGY, from any Foreign Company under interchange arrangements which require no cash settlements shall be as follows; viz:

7.61 SYSTEM INTERCHANGE FROM FOREIGN COMPANY - All energy received from Foreign Company by either a particular Member or by the Members collectively through arrangements made on their behalf by Agent, which requires no cash settlement, except INTERCHANGE ECONOMY ENERGY.

7.62 MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, the SYSTEM INTERCHANGE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.63 MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM


Illustrative Cost Allocation
$ and $/MWh
Market Clearing Price ($/MWh) & Total Dispatch Cost ($)
No Load Cost ($)
0
Internal Load
Total Dispatch Level
Generation (MW)
Dispatch Supply Curve "Stack"
OSS Cost Allocation
OSS Margin
Incremental Cost of Internal Load

Working to Perfect the Flow of Energy

PJM Manual 15:

Cost Development Guidelines

Revision: 25

Effective Date: July 28, 2014

Prepared by:

Cost Development Subcommittee

2.4.1 Start Cost Definitions

Start Cost – is the dollars per start as determined from start fuel, total fuel-related cost, performance factor, electrical costs, start maintenance adder, and additional labor cost, if required above normal station manning levels.

$$\text{Start Cost } (\$ / (\text{Start})) =$$

$$[\text{Start Fuel } (\text{MBTU} / (\text{Start})) * \text{TFRC}(\$ / (\text{MBTU}) * \text{Performance Factor})]$$

$$+[\text{Station Service } (\text{MWh}) * \text{Station Service Rate } (\$ / (\text{MWh}))]$$

$$+\text{Start Maintenance Adder } (\$ / \text{Start}) + \text{Start Additional Labor Cost } (\$ / \text{Start})$$

Station Service Rate – A $/MWh value based on the 12-month rolling average off-peak energy prices updated quarterly by the Office of the Interconnection. Station Service Rates Link.

Start Fuel - Fuel consumed from first fire of start process (initial reactor criticality for nuclear units) to breaker closing (including auxiliary boiler fuel) plus fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements

Start Maintenance Adder – see Section 2.6

Start Additional Labor Cost – Additional labor costs for startup required above normal station manning levels.

2.4.2 Engineering Judgment in Start Costs

A Unit Owner may apply engineering judgment to manufacturers' data, operational data, or the results of start tests in order to derive the components of unit start cost. A record of the results of these determinations shall be kept on file by each Unit Owner for use as a single, consistent basis for scheduling, operating, and accounting applications. These records shall be made available to the PJM MMU or PJM upon request.

2.5 No Load

2.5.1 No-Load Definitions

No-load cost is the hourly fixed cost, expressed in $/hr, required to create the starting point of a monotonically increasing incremental cost curve.

2.5.2 No-Load Fuel

All PJM members shall develop no-load costs for their units. The no-load heat input may be determined by collecting heat input values as a function of output and performing a regression analysis. The heat input values as a function of output may be either created from heat rate test data or the initial design heat input curve for an immature unit.

The minimum number of points to develop a heat input curve shall be 2 points for a dispatchable unit with a variable output and 1 point for a unit with a fixed output.

Sufficient documentation for each generating unit's no-load point in MBTUs (or fuel) per hour shall consist of a single contact person and/or document to serve as a consistent basis for scheduling, operating and accounting applications The MMU can verify calculation methods used subject to the Cost Methodology and Approval Process including the elements of Attachment B.

2.5.3 No Load Calculation

The initial estimate of a unit's **No-Load Cost ($/Hr)** is the No-Load fuel Cost multiplied by the performance factor, multiplied by the (Total Fuel-Related Cost (TFRC))

$$\text{No Load Cost}(\$ / \text{Hour}) =$$

$$(\text{No Load Fuel} * \text{Performance Factor} * \text{TFRC})$$

The unit's generator offer curve must comply with PJM's monotonically increasing curve requirement. In some instances, the calculated no-load cost may have to be adjusted to ensure that the slope of the generator offer curve is monotonically increasing. The No-Load cost adjustment is limited to a maximum difference of $1/MW between the unit's first and second incremental cost offers.

As an alternative to adjusting the no-load cost, The no-load cost may also be calculated by subtracting the incremental cost (unit's economic minimum cost-offer value multiplied by MW value) at the unit's economic minimum point from the total cost (from the heat input at economic minimum value) at the unit's economic minimum point.

$$\text{No Load Cost}(\$ / \text{Hour}) =$$

$$(\text{Economic Minimum Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM}))$$

$$- (\text{Economic Minimum Incremental Cost } (\$/\text{MWH}) * \text{Economic Minimum (MW)})$$

Note that if the unit of VOM is in terms of dollars per Equivalent Service Hours (ESH), the equation changes to:

$$\text{No Load Cost}(\$ / \text{Hour}) =$$

$$(\text{Economic Minimum Heat Input} * \text{Performance Factor} * \text{TFRC}) + \text{VOM}$$

$$- (\text{Economic Minimum Incremental Cost } (\$/\text{MWH}) * \text{Economic Minimum (MW)})$$

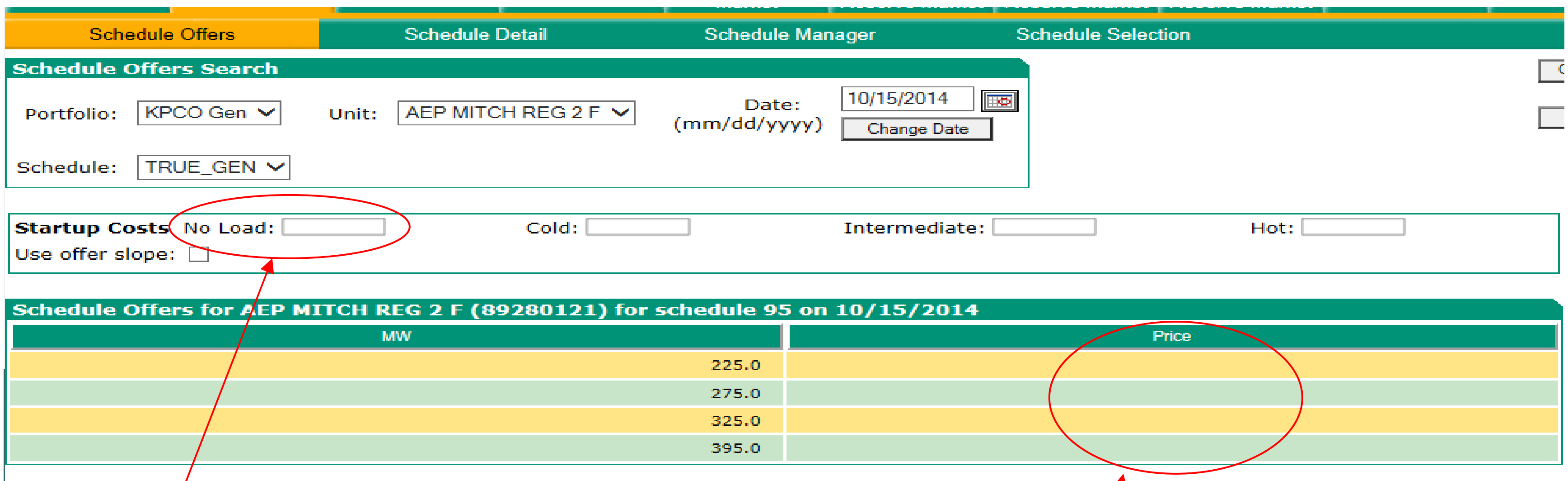
When using No Load Fuel to calculate No Load Cost, the user must submit block average cost and cannot select "Use Offer Slope" when entering cost information into eMKT. When using the alternative incremental cost method to calculate No-Load, the user must submit incremental cost and select "Use Offer Slope" when entering cost information into eMKT.

2.6 Variable Maintenance Cost

Variable Maintenance cost is the parts and labor expenses of maintaining equipment and facilities in satisfactory operating condition.

$$\text{Total Maintenance Cost}_{\text{next year}} =$$

PJM eMKT Screenshot of Mitchell 2



$/hour cost not associated with any MWh output.

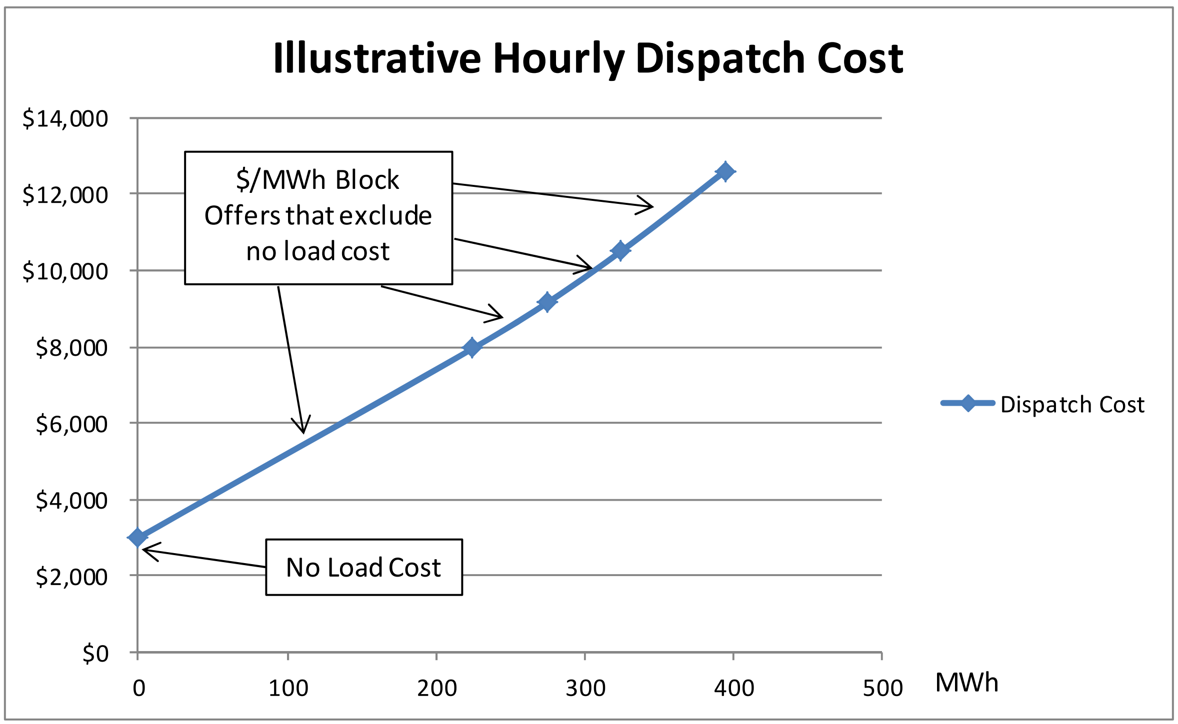
$/MWh incremental offer cost of each block of energy. **These cost do not include any no load cost.** Higher blocks have a higher $/MWh value.

ILLUSTRATIVE VALUES

No Load Cost = $3,000 /hour

Block Offer (MWhs)	Incremental Cost ($/MWh)
225	$22
275	$24
325	$27
395	**$30**

Most Expensive incremental cost is allocated to off system sales first.



KPCO Internal Load Fuel Cost
Estimated Jan-April 2014 Impact without Mitchell
(Dollars in $Millions unless noted)

2014	Actual as Occurred	Estimate without Mitchell	Fuel (Decrease) /Increase due to Mitchell	Internal Load (GWhs)	$/MWh Impact (Decrease) /Increase
(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)=(4)/(5)
January	$25.6	$31.0	($5.3)	796	($6.71)
February	$20.4	$20.4	($0.0)	643	($0.01)
March	$18.0	$24.3	($6.3)	616	($10.27)
April	$16.4	$14.6	$1.8	484	$3.65
Total	$80.3	$90.2	($9.9)	2,539	**($3.90)**