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**

JOINT BRIEF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. AND ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

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December 23, 2014

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Kentucky Industrial Utility Customers, Inc. ("KIUC") and Jack Conway, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention (collectively, "Joint Intervenors") submit this Brief in support of their recommendations to the Kentucky Public Service Commission ("Commission" or "KPSC"). The members of KIUC who are participating in this proceeding are: Air Products and Chemicals, Inc., Air Liquide Large Industries U.S. LP, AK Steel Corporation, EQT Corporation, and Marathon Petroleum Company LP. These companies purchase electricity from Kentucky Power Company ("Kentucky Power" or "Company"). Joint Intervenors' recommendations are set forth below.

INTRODUCTION

This Commission regulates dozens of large utilities in electric, gas, water, sewer, and telephone and handles hundreds of cases each year. It must do so even though its staffing levels are relatively small compared to other state commissions that regulate American Electric Power ("AEP") utilities. Given its smaller size, the Commission must be able to rely on the representations of the regulated utilities as truthful and accurate for its regulation to continue to be effective and efficient. But Kentucky Power has recently presented a series of incorrect or misleading claims to the Commission that, if not properly addressed, could prolong the harm to customers in its territory, i.e. the unjust and unreasonable fuel adjustment clause ("FAC") rates Kentucky Power has charged and is presently charging its customers.

One misleading claim by Kentucky Power was that the Company's acquisition of 50% of Mitchell Units 1 and 2 from its affiliate proposed in Case No. 2012-00578 ("Mitchell Transfer Case") would result in $16.75 million in fuel savings to customers.[1] This claim completely ignored $38.252 million in additional *"no load"* fuel costs that customers would be forced to pay after the Mitchell transfer.[2] Kentucky Power now alleges that at the time the July 2, 2013 Stipulation was filed in the Mitchell Transfer Case, the Company did not know the full magnitude of the impact that the additional *"no load"* costs would have on customers.[3] Even if that is true, Kentucky Power did not inform KPSC Staff and Intervenors about the existence of *"no load"* costs or how they were treated in the FAC until an informal conference held June 26, 2014.[4] And even in the Company's presentation for that meeting, the issue was glossed over.[5]

Kentucky Power continues to present incorrect or misleading claims regarding the financial effects of the Mitchell transfer on customers, attempting to explain away the fact that the 5.33% rate increase that Kentucky Power represented would occur was actually a 15.0% rate increase.[6]

As discussed below, the Commission should not be swayed by Kentucky Power's series of incorrect or misleading claims. Rather, in order to protect ratepayers and the integrity of the regulatory process, the Commission should order the full refund allowed under the law, plus interest.

SUMMARY

Kentucky Power's fuel cost allocation approach during the review period was improper and harmed native load customers, forcing them to pay at least $12.648 million in unjust and unreasonable FAC charges in violation of 807 K.A.R. §5:056 and KRS §278.030(1). Under the Company's approach, its native load ratepayers paid above-average costs for fuel while its market-based off-system sales were charged below-average costs for fuel. Because the subsidization of off-system sales that occurred during the review period was largely the result

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[1] Stipulation and Settlement Agreement (July 2, 2013), Case No. 2012-00578 ("Stipulation") at 5.
[2] KIUC Ex. 1, Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 9.
[3] Tr. at 67:17-19; KIUC Ex. 5, Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 10.
[4] KIUC Ex. 5.
[5] KIUC Ex. 7, Kentucky Power Company Presentation, *"Termination of Pool and acquisition of 50% of the Mitchell Plant effects on the Fuel Adjustment Clause."* (June 26, 2014).
[6] KIUC Ex. 8, Case No. 2012-00578, Kentucky Power Response to Commission Staff's Fifth Set of Data Requests, Item No. 10 (June 26, 2013); Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 11, Attachment 1.

of the Company's FAC accounting for affiliate purchases from the Mitchell and Rockport units, provisions of KRS §278.2201 through §278.2215, which protect customers from affiliate abuse, may have also been violated.

From January 1, 2014 through April 30, 2014, Kentucky Power's average fuel cost for all sales was $28.49 per MWh. But the fuel cost allocated to the Company's native load customers was $31.67 per MWh. In stark contrast, the average fuel cost allocated to off-system sales was only $24.13 per MWh.[7]

The problem with Kentucky Power's approach leading to such a result during the review period, which continues to this day, is that the Company allocates 100% of its *"no load"* fuel costs (totaling $40.045 million during the review period) for all six of its generating units to native load customers and none to off-system sales customers.[8] *"No load"* costs represent the costs of fuel input into a generator in order to keep the generator operating, but without actually producing any electricity. Generating units do not operate in this manner,[9] and therefore, the concept of *"no load"* costs exists more as a mathematical concept rather than a real cost.[10] That is why PJM Interconnection, LLC ("PJM") repeatedly refers to *"no load"* fuel costs as *"theoretical."*[11] Kentucky Power assigned 100% of the "*theoretical*" *"no load"* fuel costs associated with all six of its generating units to native load customers, even when those units were not necessary to serve native load. Kentucky Power's fuel cost allocation approach is contrary to the principle of cost causation and results in cost-shifting to native load customers in order to subsidize and enhance the profitability of its market-based off-system sales. And Kentucky Power has retained 100% of the profits from those off-system sales since January 1, 2014 pursuant to the Mitchell Transfer Case Stipulation.[12]

The harm to customers from Kentucky Power's improper fuel cost allocation approach was exacerbated during the review period due to the Company's acquisition of 50% of the Mitchell generating units (780 MW) on January 1, 2014.[13] The Commission authorized Kentucky Power to acquire the Mitchell units by approving the Stipulation filed in the Mitchell Transfer Case. But in that case, Kentucky Power failed to disclose the material

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[7] Kollen Testimony at 4:1-4.
[8] Kollen Testimony at 4:5-8.
[9] Tr. at 48:5-19.
[10] Hayet Testimony at 7:6-10.
[11] Kollen Testimony at 10:3-7 (citing KIUC Ex. 10, *"No-Load Definition: Educational Document,"* PJM Interconnection LLC, *available at* http://www.pjm.com/~/media/committees-groups/subcommittees/cds/20110620/20110620-item-03b-cds-educational-paper-for-no-load.ashx).
[12] Stipulation at 7.
[13] Tr. at 34:21-35:2.

fact that the Mitchell transfer would force native load customers to pay an additional $38.252 million in annual theoretical *"no load"* fuel costs associated with the Mitchell units through their FAC rates beginning January 1, 2014.[14] Instead, the Company claimed, incorrectly, that customers would achieve $16.75 million in annualized fuel savings after the Mitchell units were transferred on January 1, 2014.[15] The Commission relied on the Company's claimed savings in approving the transaction, as did the other parties who agreed to the Stipulation in that proceeding.[16] Ultimately, while Kentucky Power represented that the rate increase to customers resulting from the Mitchell transfer beginning January 1, 2014 would be 5.33%,[17] the rate increase after the *"no load"* fuel costs are taken into account was 12.81%.[18] And the actual rate increase to customers beginning January 1, 2014 after all of the Mitchell transfer-related components are taken into account was 15.0%.[19]

Kentucky Power now attempts to recast the impacts of the Mitchell transfer on FAC rates in a positive light through additional fuel savings estimates, but its representations rely on unrealistic or incorrect assumptions.

Company witness Wohnhas now claims that the Mitchell transfer resulted in $14.8 million in annual fuel savings to customers, which is 89% of the promised savings of $16.75 million.[20] But his analysis: 1) fails to account that some of those savings accrued to off-system sales customers, not native load customers; and 2) again ignores the central issue in the case – the $38.252 million in additional annual *"no load"* costs associated with the Mitchell transfer.

In a one-page exhibit submitted in rebuttal, Company witness Pearce claims that without the Mitchell transfer fuel costs for native load customers would have been $9.9 million higher from January through April 2014.[21] Post-hearing data responses reveal, however, that Dr. Pearce assumed that without the Mitchell transfer Kentucky Power would have been forced to make large amounts of expensive replacement power purchases and he then incorrectly assigned 100% of those replacement purchases to native load.[22] Dr. Pearce also

[14] KIUC Ex. 1.
[15] Stipulation at 5.
[16] Mitchell Transfer Case, Order (October 7, 2013) at 33.
[17] KIUC Ex. 8.
[18] KIUC 1.
[19] Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 11, Attachment 1.
[20] Rebuttal Testimony of Ranie K. Wohnhas (November 5, 2014)("Wohnhas Rebuttal") at 6:5-9 (citing RKW-1).
[21] Rebuttal Testimony of Kelly Pearce (November 5, 2014) at 20:10-13 (citing KDP-5).
[22] *See* Attachment, Kentucky Power Company Response to Commission Staff's November 12, 2014 Post Hearing Data Requests, Item No. 7, Attachment 1.

simultaneously assumed that the volume and price of purchases made for off-system sales would be exactly the same with or without the Mitchell transfer, contrary to the Company's own fuel cost allocation approach, which assigns the highest cost purchases to off-system sales.[23] Accordingly, Dr. Pearce did not prove, nor did he attempt to prove, what customer FAC rates would have been without the Mitchell transfer. Dr. Pearce simply proved a fact not in dispute – that purchased power is generally more expensive than generation from the Mitchell units.

Perhaps Kentucky Power's most misleading claim is that the "*polar vortex*" was to blame for the increase in customer rates from the promised 5.33% to approximately 15.0%.[24] The Company's own documents show that "*no load*" costs were higher in April 2014 than in February 2014, a month when Kentucky Power states that "*polar vortex*" occurred.[25]

Although Kentucky Power's "*no load*" fuel costs are more aptly characterized as "*variable*" costs, the Company claims that those costs are "*fixed.*"[26] Even accepting Kentucky Power's characterization, those "*no load*" fuel costs should still be fairly allocated between native load customers and off-system sales customers. Such an approach is consistent with Commission precedent requiring Kentucky Power and the other Kentucky utilities to fairly allocate "*fixed*" environmental compliance costs between native load customers and off-system sales in the monthly environmental surcharge. The Commission's rationale in the environmental surcharge cases – that the "*fixed*" costs incurred in order to make off-system sales should be proportionately allocated to off-system sales customers - is equally applicable to this case.

When it comes to fuel cost allocation approaches, Kentucky Power is an outlier. No other utility in Kentucky explicitly segregates out "*no load*" fuel costs and allocates those costs entirely to native load customers. The glaring inconsistency is especially problematic since the uniform FAC regulation applies equally to all utilities. Moreover, unlike many other regulations, the FAC regulation does not contain a provision allowing for deviation upon a showing of good cause. Kentucky Power's fuel cost allocation approach also runs counter to the guidance provided by the Federal Energy Regulatory Commission ("FERC") in cases finding that

[23] *Id.*
[24] Wohnhas Rebuttal at 6:16-19.
[25] KIUC Ex. 4, Kentucky Power Company Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 2; Tr. at 73:9-74:9.
[26] Tr. at 47:22-23; Kentucky Power Response to KIUC First Set of Data Requests, Item No. 3.

native load customers are entitled to the utility's lowest cost generation and should not be forced to subsidize off-system sales.

Because Kentucky Power's fuel cost allocation approach during the review period was improper, resulting in unreasonably high FAC charges to native load customers, the Commission should order Kentucky Power to refund $13.512 million to customers over a six-month period ($12.648 million in excessive fuel costs collected from native load customers from January 1, 2014 through April 30, 2014 plus $0.864 million in interest). Interest at the weighted average cost-of-capital should continue to run until the refund is fully satisfied. The Commission should also direct Kentucky Power to modify its fuel cost allocation approach by adopting the methodology used by East Kentucky Power Cooperative ("EKPC") and Duke Energy Kentucky, Inc. ("Duke") on a going-forward basis. This will result in reasonable FAC rates and promote uniformity regarding the application of the FAC regulation.

ARGUMENT

I. Kentucky Power's Fuel Cost Allocation Approach Caused Native Load Customers To Pay A Disproportionate Amount of Fuel Costs During the Review Period.

Kentucky Power's fuel cost allocation approach during the review period was as follows: Each month, Kentucky Power performed an *"after-the-fact"* reconstruction to allocate fuel costs between native load customers and off-system sales customers.[27] In the first step, Kentucky Power calculated the theoretical *"no load"* fuel costs for its six generating units and assign 100% of those costs to native load customers.[28] The amount of *"no load"* fuel costs assigned to native load customers totaled $40.045 million during the six-month review period, with $31.649 million of those costs being collected from native load customers in January through April 2014.[29] In the second step (which is new and began after the Mitchell transfer occurred),[30] Kentucky Power allocated its other *"minimum segment"* fuel costs between native load and off-system sales. However, under this new second step, off-system sales would be allocated these *"minimum segment"* fuel costs only in hours when

[27] Kollen Testimony at 6:17-19.
[28] Hayet Testimony at 4:18-20.
[29] KIUC Ex. 2, Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 2; Kollen Testimony at 7:8-11 and 17:3-6. This represents 25% of the total fuel costs ($124,284,693) charged during that period.
[30] Kollen Testimony at 8:7-12; Hayet Testimony at 5:3-4 and 11:9-12:11.

Kentucky Power had so much excess capacity that the minimum operating levels of its units exceeded its native load.[31] In the final step, Kentucky Power allocated the remaining fuel costs between native load and off-system sales by economically *"stacking"* those costs in dispatch order.[32]

The problem with Kentucky Power's fuel cost allocation approach lies in its first step – the Company's assignment of 100% of its theoretical *"no load"* fuel costs to native load customers despite the fact that a portion of those costs were incurred to enable and support off-system sales.[33] This first step runs counter to the principle of cost causation, results in Kentucky Power's native load customers being charged higher prices for fuel than its off-system sales customers, and unreasonably subsidizes the Company's off-system sales profits.[34]

For instance, Kentucky Power's average fuel cost from January through April 2014 was $28.49 per MWh. But the average fuel cost allocated to native load customers during that period was $31.67 per MWh. In contrast, the average fuel costs allocated to market-based off-system sales customers during that period was $24.13 per MWh. Consequently, Kentucky Power allocated approximately 31% more in fuel costs on a $ per MWh basis to native load customers than to off-system sales customers during that period.[35]

The following table presents the fuel costs allocated to native load customers and off-system sales customers on a $ per MWh basis by month from January through April 2014.[36]

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[31] Kollen Testimony at 7:16-23; Hayet Testimony at 5:7-12.
[32] Kollen Testimony at 8:1-6.
[33] Tr. at 50:1-10 ("Q: *Could you make electricity without incurring the no-load cost? A: No. Q: So in order to sell power on system, you have to incur the no-load cost? A: Yes. Q: And in order to generate electricity, so off-system, you have to incur the no-load cost, correct? A: If no-load cost is incurred, yes."*).
[34] Kollen Testimony at 9:1-6.
[35] Kollen Testimony at 14:3-12 (citing Ex. LK-3).
[36] KIUC Ex. 3, Kentucky Power Fuel Generated Fuel Cost Allocation; Hayet Testimony at 9:1; KIUC 2.

Table 1

Kentucky Power Fuel Generated Fuel Cost Allocation Native Load and Off-System Sales ($/MWH)	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014
Fuel Cost	29.38	29.34	27.18	27.83
Allocation to Off-System Sales	24.42	25.95	24.39	22.36
Allocation to Native Load	32.14	31.61	28.99	34.40

For more detail, the following table compares the average April 2014 fuel cost of only the Mitchell units with the cost per MWh allocated to native load and off-system sales:[37]

Table 2

	April 2014 Fuel Cost ($/MWh)	Fuel Cost Allocated to Off-System Sales ($/MWh)	Fuel Cost Allocated to Native Load ($/MWh)
Mitchell 1	24.12	18.21	29.44
Mitchell 2	28.45	17.92	36.93

As the table above reflects, in April 2014 native load customers paid approximately 62% more in fuel costs for Mitchell Unit 1 and approximately 106% more in fuel costs for Mitchell Unit 2 than the cost allocated to off-system sales.[38]

Kentucky Power's pattern of allocating native load customers above-average costs for fuel while allocating off-system sales below-average costs for fuel costs occurred in other months as well and with respect to other generating units, as demonstrated below.[39]

[37] KIUC Ex. 2.
[38] KIUC Ex. 2.
[39] Kollen Testimony at 13:10-14:1.

Table 3

KENTUCKY POWER COMPANY COMPARISON OF ACTUAL FUEL EXPENSE PER MWH, FUEL EXPENSE PER MWH CHARGED TO RETAIL NATIVE LOAD CUSTOMERS, AND FUEL EXPENSE PER MWH ALLOCATED TO OFF-SYSTEM SALES	Nov. 2013	Dec. 2013	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014
Rockport 1						
Fuel Cost $ Per MWH By Generating Plant	25.54	25.36	24.21	25.96	22.19	25.38
Fuel Cost $ Per MWH Allocated to Off-System Sales	23.33	23.21	22.13	23.59	22.41	22.88
Fuel Cost $ Per MWH Allocated to Native Load	25.94	26.62	25.73	28.55	22.07	28.95
Rockport 2						
Fuel Cost $ Per MWH By Generating Plant	25.35	25.15	23.94	26.66	22.23	26.13
Fuel Cost $ Per MWH Allocated to Off-System Sales	23.23	23.04	21.91	23.30	21.97	22.63
Fuel Cost $ Per MWH Allocated to Native Load	25.71	26.15	25.22	28.93	22.35	30.68
Mitchell 1						
Fuel Cost $ Per MWH By Generating Plant			31.91	37.66	30.64	24.12
Fuel Cost $ Per MWH Allocated to Off-System Sales			23.83	23.94	24.67	18.21
Fuel Cost $ Per MWH Allocated to Native Load			33.82	38.56	35.35	29.44
Mitchell 2						
Fuel Cost $ Per MWH By Generating Plant			29.17	29.46	25.34	28.45
Fuel Cost $ Per MWH Allocated to Off-System Sales			23.78	25.01	23.45	17.92
Fuel Cost $ Per MWH Allocated to Native Load			30.69	30.17	26.14	36.93
Big Sandy Plant						
Fuel Cost $ Per MWH By Generating Plant	57.88	34.82	31.18	29.54	31.38	30.22
Fuel Cost $ Per MWH Allocated to Off-System Sales	32.00	54.51	25.59	26.79	26.22	24.75
Fuel Cost $ Per MWH Allocated to Native Load	62.53	18.44	35.29	32.54	36.25	38.27

As shown above, Kentucky Power's fuel cost allocation approach also resulted in higher FAC charges to native load customers during lower usage months (i.e. April) because the same amount of *"no load"* fuel costs were being allocated to native load customers, but collected over a smaller number of kilowatt hour sales. This is contrary to proper economic dispatch. Under proper economic dispatch, during low usage months the FAC rate should be lower as the utility's least cost units are available to serve native load. This further illustrates why Kentucky Power's fuel cost allocation approach was improper.[40]

Not all of Kentucky Power's generating units even lent themselves well to the Company's fuel cost allocation approach, i.e. the Rockport units owned by Kentucky Power's affiliate, Indiana Michigan Power ("I&M"), to which Kentucky Power has 15% entitlement through long-term purchase power agreements. Each month, Kentucky Power receives an invoice from AEP Service Corp. for the Rockport fuel costs associated with its entitlement. Those AEP invoices do not segregate Rockport *"no load"* fuel costs from other fuel costs. Rather, they simply charge Kentucky Power an overall cost for *"Fuel."* Kentucky Power then performs an

[40] Kollen Testimony at 15:3-9.

"after-the-fact" calculation to segregate out the theoretical *"no load"* fuel costs from the other Rockport fuel costs for FAC purposes, which results in Kentucky Power effectively *"marking up"* the Rockport fuel allocated to native load. For example, in February 2014, Kentucky Power purchased Rockport energy at a fuel cost of $26.31 per MWh. In its *"after-the-fact"* reconstruction, Kentucky Power allocated a portion of that fuel cost to native load customers at $28.76 per MWh and allocated the rest to off-system sales at $23.463 per MWh.[41] This allowed Kentucky Power to unreasonably profit from this affiliate purchase.[42]

Kentucky Power's improper assignment of 100% of its theoretical *"no load"* fuel costs entirely to native load customers during the review period meant that those customers were assigned a disproportionate share of the Company's total fuel costs.[43] Native load represented 58% of Kentucky Power's sales during that period. Yet Native load customers were allocated 64% of Kentucky Power's fuel costs.[44] And every dollar in fuel costs that was shifted to native load customers represented an additional dollar in off-system sales margins that the Company got to keep as a result of the Stipulation in the Mitchell Transfer Case.[45] Kentucky Power's off-system sales margins were therefore improperly subsidized during the review period because the FAC rate charged to native load customers during that period was excessive and unreasonable.[46]

KRS §278.2207(1)(b) requires that services or products provided to a utility from an affiliate shall be priced at the affiliate's fully distributed cost, but in no event greater than market. The initial sale of Rockport energy from I&M to Kentucky Power at cost complies with this statute. But Kentucky Power's FAC practice of charging native load consumers more for fuel than its affiliate charged appears to violate KRS §278.2207(1)(b). This statutory violation is then compounded when the FAC allocation process is used to subsidize Kentucky Power's market based off-system sales, which may be considered a non-regulated activity. This would violate KRS §278.2201. The laws of this Commonwealth are structured to prevent affiliate transactions from harming consumers by subsidizing shareholders. Charging native load consumers more for Rockport fuel than it actually costs violates that protection. In a broader sense, the FAC treatment of both the Rockport and Mitchell affiliate

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[41] KIUC Ex. 2; Kentucky Power Response to KIUC First Set of Data Requests, Item No. 5.
[42] Kollen Testimony at 11:15-12:13 (citing Exhibit LK-2).
[43] Kollen Testimony at 9:16-19.
[44] Kollen Testimony at 17:8-11 (citing Exhibit LK-3).
[45] Kollen Testimony at 7:3-6; Hayet Testimony at 5:21-6:1.
[46] Kollen Testimony at 7:1-3.

purchases can be seen as part of a comprehensive system to subsidize and inflate the profits associated with non-regulated market based off-system sales.

II. Kentucky Power Improperly Allocated 100% Of The Theoretical *"No Load"* Fuel Costs Associated With All Six Of Its Generating Units To Native Load Customers, Even Though Not All Of Those Units Were Always Necessary To Serve Its Native Load Customers.

Kentucky Power currently has a significant amount of excess capacity as a result of the Mitchell transfer.[47] In its recent Integrated Resource Planning Report, the Company projected its 2014 reserve margin at 57.3%.[48] Because Kentucky Power has such a significant amount of excess capacity, it can make a substantial amount of off-system sales with those generating units. In the first quarter of 2014 alone, the Company made more off-system sales (2,063 GWh) than it did in all of 2013 (1,801 GWh).[49] In fact, off-system sales constituted 42% of Kentucky Power's total sales from January 1, 2014 through April 30, 2014.[50] And in April 2014, Kentucky Power sold more power off-system than on-system.[51] Because of its substantial excess capacity, Kentucky Power does not always need all of its generating units to serve its native load. Indeed, for 31% of the hours of the January-April 2014 period, Kentucky Power's native load was less than the *minimum* operating levels of all of the Company's generating units (975 MW).[52] Yet even in times when some of Kentucky Power's generating units were used solely to make off-system sales, native load customers paid 100% of the *"no load"* costs associated with those units.[53]

Moreover, Kentucky Power did not alter the amount of *"no load"* fuel costs allocated to native load based upon how much power native load received from a particular unit. Mr. Wohnhas discussed this issue at the hearing:

> *Q: April '14, Big Sandy Unit 2 native load received 39.5 percent of the output of Big Sandy 2?*
> *A. Yes.*
> *Q: Now, if you look on KIUC 4 at the bottom, Big Sandy 2 in April, what was the no-load cost?*
> *A: Big Sandy 2?*

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[47] Tr. at 35:19-23 (*"So for the –for the 17-month period January 1, 2014 through May 31, 2015, you're going – Kentucky Power has more power than it needs for native load. Is that a fair statement? That's fair."*).
[48] Integrated Resource Planning Report, Case No. 2013-00475 (December 20, 2013) at 14; Tr. at 35:3-11.
[49] Hayet Testimony at 8:11-12.
[50] Kollen Testimony at 21:2-4.
[51] KIUC Ex. 2.
[52] Tr. at 42:18-43:19.
[53] Kollen Testimony at 11:6-13; Tr. at 86:1-87:3.

Q: Yes.
A: [$]4,250,145.
Q: Okay. And in that month native load paid all that no-load cost, correct? Because you treat it as a fixed cost?
A: Yes.
Q: Okay. Now, what if native load had only received one megawatt hour out of Big Sandy 2? Native load would have still got charged that same $4.2 million, correct?
A: In theory. You are not going to generate one megawatt hour, but yes.[54]

Kentucky Power also failed to dedicate its lowest fuel cost generating units solely to native load customers, instead using them to make off-system sales. A significant portion of the Rockport 1 and 2 generation was allocated to off-system sales during the review period instead of being retained by native load customers. As shown on Table 3, the Rockport generating units generally have the lowest fuel costs on Kentucky Power's system, averaging $24.77/MWh for Rockport Unit 1 and $24.91/MWh for Rockport Unit 2 ($24.64/MWh and $24.73/MWh respectively on a weighted average basis) during the review period. The 390 MW provided by the Rockport units alone is sufficient to meet approximately 40% of Kentucky Power's native load energy requirements. Yet Kentucky Power allocated a significant amount of the low-cost Rockport generation to off-system sales, allocating an average of 44% of the Rockport generation and related fuel costs to off-system sales from January through April 2014.[55] Under the economic *"stacking"* approach used by EKPC, Duke, and other utilities for FAC purposes, Rockport would be at the bottom of the generation stack and assigned to native load first as the least-cost resource.

As shown on Table 3, the Big Sandy generating units generally have the highest fuel costs on Kentucky Power's system, averaging $35.84/MWh ($31.59/MWh on a weighted average basis) during the review period. With the Rockport and Mitchell units operating, neither of the Big Sandy units is typically needed to meet the Company's native load energy needs.[56] Even at the Company's winter peak, Big Sandy 1 and a significant portion of Big Sandy 2 were not needed to meet the native load energy needs.[57] Yet Kentucky Power allocated a significant amount of those high Big Sandy fuel costs to native load customers in all hours they were available

[54] Tr. at 56:20-57:12.
[55] KIUC Ex. 2.
[56] *See* Kentucky Power Response to KIUC First Set of Data Requests, Item No. 11.
[57] The Attorney General has appealed the Mitchell transfer case to Franklin Circuit Court and maintains that Big Sandy 2 remains a valuable asset for Kentucky Power's ratepayers and for the Commonwealth of Kentucky. The Attorney General continues to oppose Kentucky Power's lack of an independent assessment regarding the future of this unit.

and operating, assigning an average of approximately 56% of Big Sandy Unit 1 and 47% of Big Sandy Unit 2 to native load customers from January through April 2014.[58] Under the economic *"stacking"* approach used by EKPC, Duke, and other utilities for FAC purposes, the Big Sandy units would be at the top of the generation stack and rarely assigned to native load as the last resource.

III. Kentucky Power Failed To Account For The Harmful Impacts Of Its Improper Fuel Cost Allocation Approach When It Claimed That There Would Be $16.75 Million In Fuel Savings To Native Load Customers As A Result of the Mitchell Asset Transfer.

In the Mitchell Transfer Case, Kentucky Power represented that transferring 50% of Mitchell Units 1 and 2 to the Company would result in approximately $16.75 million in annual fuel savings to native load customers.[59] Specifically, the Stipulation in that case provided:

> *Because of the anticipated lower fuel costs of Mitchell Units 1 and 2 vis-a-vis the anticipated fuel costs of the Big Sandy units, the transfer of the Mitchell units to Kentucky Power is expected to provide Kentucky Power customers with the benefit of reduced fuel costs of approximately $2.50/MWh. Based on 2012 jurisdictional kWh sales of 6.7 GWh, the benefits are estimated to total $16.75 million annually.*[60]

In its Order approving the Stipulation, the Commission cited the anticipated $16.75 million in annual fuel savings.[61]

Kentucky Power's representations in the Mitchell Transfer Case were incorrect. Instead of $16.75 million in fuel savings, the Mitchell transfer resulted in additional *"no load"* fuel costs being allocated to native load customers beginning January 1, 2014. Specifically, from January 1, 2014 through April 30, 2014, Kentucky Power's native load customers were charged $13.155 million in Mitchell *"no load"* costs in addition to the *"no load"* costs associated with the Company's other generating units. The Company has estimated the annual Mitchell *"no load"* costs at $38.252 million.[62]

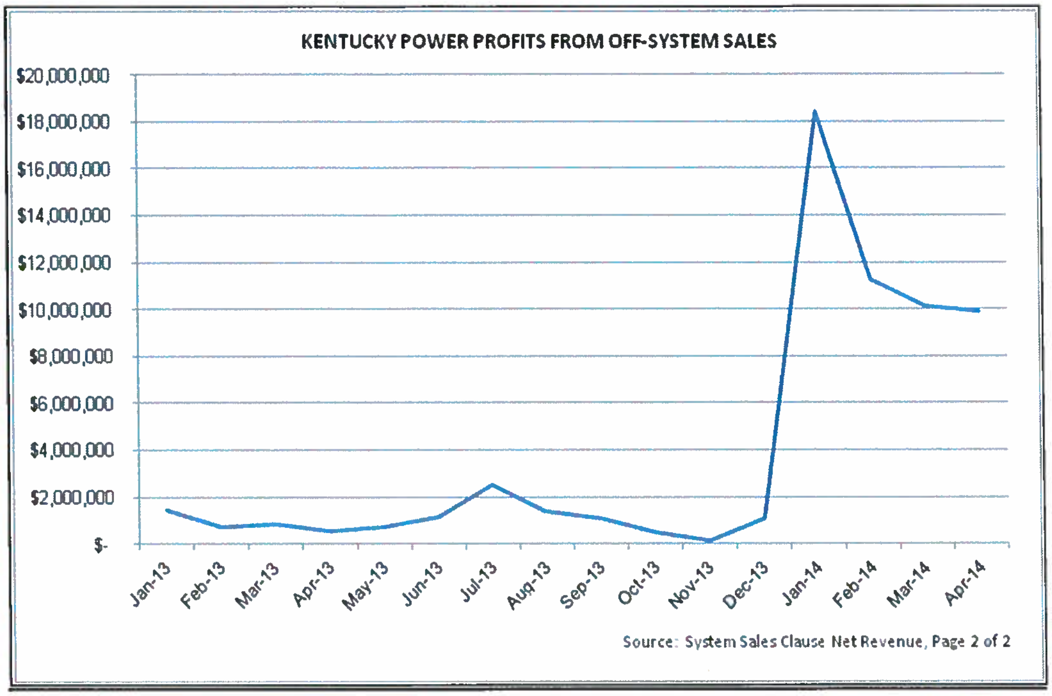
[58] KIUC Ex. 2.
[59] Kollen Testimony at 25:9-12 (citing Exhibit LK-6); Tr. at 36:15-23.
[60] Stipulation at 5.
[61] Order, Case No. 2012-00578 (October 7, 2013) at 33.
[62] KIUC Ex. 1; Kollen Testimony at 25:25-26:6.

During the Mitchell Transfer Case, Kentucky Power failed to inform Staff and other parties of the additional $38.252 million in annual "*no load*" fuel costs associated with the Mitchell units. Kentucky Power states that it was not aware of the magnitude of the "*no load*" costs at the time the Stipulation was filed.[63] While Kentucky Power did eventually set up an informal conference to discuss the "*no load*" issue with Staff and Intervenors, that conference did not take place until June 26, 2014.[64] The 23-page PowerPoint presentation from the June 26, 2014 conference barely even mentioned the "*no load*" issue.[65] It was glossed over.

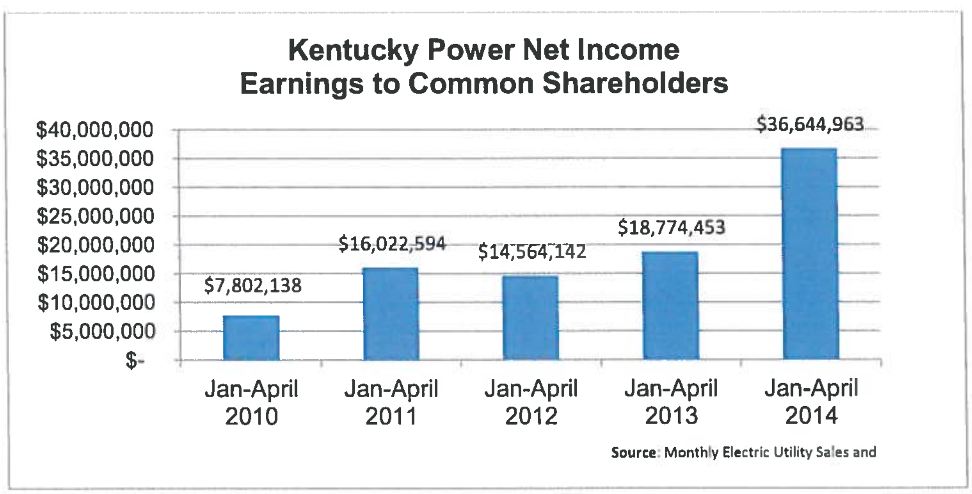
Rather than receiving the 5.33% rate increase projected by Kentucky Power in the Mitchell Transfer Case,[66] the actual rate increase to customers was 15.0%.[67] A large portion of that increase was the result of the additional $38.252 million in annual "*no load*" costs associated with the Mitchell units that were allocated entirely to native load customers beginning January 1, 2014. Including those Mitchell "*no load*" fuel costs in the Company's Mitchell Transfer Case rate impact calculation amplifies the projected rate increase from 5.33% to 12.81%.[68] If the other "*minimum segment*" fuel costs from the Mitchell units were included, the projected rate increase would be even greater, thus leading to the actual 15.0% rate increase.[69]

While the Mitchell transfer resulted in an additional $38.252 million in annual theoretical "*no load*" fuel costs and other increased minimum segment costs for its native load customers in addition to a rate increase from the Asset Transfer Rider, Kentucky Power has reaped significant benefits as a result of the transfer. Pursuant to the Stipulation, Kentucky Power has retained 100% of the profits from off-system sales since January 1, 2014.[70] And those off-system sales profits were significant. Kentucky Power's off-system sales profits jumped from $1.1 million in December 2013 to $18.4 million in January 2014, $11.3 million in February 2014, $10.1 million in March 2014, and $9.9 million in April 2014. Kentucky Power's off-system sales profits from January 2013 through April 2014 are set forth in the following chart.[71]

[63] KIUC Ex. 5.
[64] Tr. at 69:9-12.
[65] KIUC Ex. 7.
[66] KIUC Ex. 8.
[67] Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 11, Attachment 1.
[68] KIUC Ex. 1.
[69] Kollen Testimony at 26:9-17.
[70] Stipulation at 7.
[71] Kollen Testimony at 27:7-28:1 (citing Exhibit LK-7 for more detail).



These significant off-system sales margins, which were substantially enhanced by an improper fuel allocation, contributed to significant total Company profits during the first four months of 2014. The chart below compares the Company's January-April profits over the last five years.[72]



By assigning 100% of its theoretical *"no load"* fuel costs to native load customers, Kentucky Power was able to reduce the fuel costs that should have been allocated to off-system sales and thus unreasonably subsidize its profit margins on those sales.

[72] Kollen Testimony at 28:2-6 (citing Exhibit LK-8).

IV. Kentucky Power's New Estimates Regarding The Fuel Savings To Native Load Customers Resulting From The Mitchell Asset Transfer Are Misleading And Wrong.

Kentucky Power witnesses attempt to recast the fuel impacts of the Mitchell transfer in a more positive light by providing new estimates of claimed fuel savings to customers stemming from the transfer. However, the Company's estimates are grounded upon unrealistic or incorrect assumptions. Try as it might, Kentucky Power cannot explain why rates went up by 15%, not the promised 5.33%.

Kentucky Power cites the *"polar vortex"* in early 2014 as a reason for the high *"no load"* costs allocated to native load customers, claiming that "*the higher no load costs are driven principally by the fact that the extreme cold weather experience during the January and February 2014 Polar Vortex created a seldom-seen and never-contemplated demand for the Company's generation.*"[73] But the impacts of the additional "*no load*" costs associated with the Mitchell transfer reverberated in milder months as well. Indeed, the Company's $7.8 million of *"no load"* costs in April 2014 (a month in which no *"polar vortex"* occurred) are higher than the Company's $7.5 million of *"no load"* costs in February 2014 (a month when Kentucky Power claims the *"polar vortex"* occurred).[74] Accordingly, Kentucky Power cannot hide behind the *"polar vortex."*

In a single page exhibit to his rebuttal testimony, Company witness Pearce estimated that Kentucky Power's native load customers would have incurred approximately $9.9 million in additional costs from January through April 2014 had the Mitchell transfer not taken place.[75] However, examining the detail surrounding Dr. Pearce's $9.9 million savings figure provided in Kentucky Power's post-hearing data responses reveals a number of flaws in that estimate.[76]

Dr. Pearce's post-hearing data response showed actual generation and purchased power assigned to both native load and off-system sales customers during April through January. He then estimated how generation and purchases would have changed without the Mitchell transfer. Without the Mitchell transfer, Dr. Pearce assumed that the amount and cost of generation from Big Sandy and Rockport units would be exactly the same.[77] He also

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[73] Wohnhas Rebuttal at 6:16-19.
[74] KIUC Ex. 4; Tr. at 73:9-74:9.
[75] Pearce Rebuttal at 20:10-13 (citing KDP-5).
[76] Attachment, Kentucky Power Company Response to Commission Staff's November 12, 2014 Post Hearing Data Requests, Item No. 7.
[77] Kentucky Power Company Response to Commission Staff's November 12, 2014 Post Hearing Data Requests, Item No. 7, Attachment 1.

assumed that the volume and price of third-party power purchases made for off-system sales would be exactly the same.[78] This was the critical flaw. By assuming no change in purchased power for off-system sales customers in the no-Mitchell scenario, Dr. Pearce filled the shortfall caused by the lack of Mitchell with extremely expensive additional purchases which he assigned entirely to native load. If this had occurred in reality, then it would be imprudent. A prudent utility would divert low-cost purchases to native load instead of reselling such low-cost purchases off-system.

For example, in January 2014 Dr. Pearce assumed that the Company's third-party power purchases for native load customers would skyrocket from $128,688 at $45.278 per MWh to $9,289,544 at $175.584 per MWh.[79] This imprudent and unrealistic assumption pushes all of the additional high cost third-party power purchases required without the Mitchell units onto native load customers. This assumption is contrary to the Company's own FAC cost allocation approach which would assign the highest purchased power costs to off-system sales. All that Dr. Pearce proved is that the fuel from Mitchell is generally less expensive than incremental purchases. That is not surprising. But he completely failed to prove how fuel and purchase power costs would have actually been incurred or allocated without Mitchell. Dr. Pearce did not prove, nor did he attempt to prove, what the FAC rate would have been without Mitchell.

Even accepting Dr. Pearce's imprudent and unrealistic assumptions that low-cost purchases would be resold off-system and that the shortfall from not having Mitchell would be filled with high-cost incremental purchases assigned 100% to native load, his analysis reflects that the Mitchell transfer is still a bad deal for customers in April 2014. According to Dr. Pearce's assumptions, the average fuel cost to native load customers in April 2014 with the Mitchell units would be $34.396 per MWh.[80] Without the Mitchell transfer, Dr. Pearce's numbers reflect that the average fuel cost would be $30.174 per MWh.[81] This shows that customers would have saved $1,768,280 in April without Mitchell. The additional cost associated with Mitchell in April could not be artificially hidden by Dr. Pearce's improper allocation of purchase power costs because April was a low-usage month with only a small amount of purchases.

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[78] *Id.*
[79] *Id.*
[80] *Id.*
[81] *Id.*

Company witness Wohnhas tried to buttress the $16.75 million fuel savings number included in the Stipulation through his Exhibit RKW-1, which reflects that from January through August 2014, the cost difference between the coal used at the Mitchell units and the coal used at Big Sandy 2 was $9,884,747, which equates to $14,827,121 in savings on an annual basis (or 89% of the savings amount estimated in the Stipulation).[82] This analysis ignores the central issue in this case. Mr. Wohnhas' savings figures still fail to reflect the additional $38.2 million in annual *"no load"* costs associated with the Mitchell units.[83] Thus, Mr. Wohnhas' savings figures are wrong. Additionally, Mr. Wohnhas does not account for the fact that not all of the power generated by Mitchell was used to serve native load.[84] In fact, only 52.58% of the Mitchell Unit 1 power and 55.38% of the Mitchell Unit 2 power served native load in April 2014.[85] Hence, off-system sales customers received some of the fuel savings that Mr. Wohnhas attributes to native load customers.

Kentucky Power witness Pearce also argues that using the EKPC/Duke fuel cost allocation methodology and allocating a portion of its *"no load"* costs to off-system sales customers "*could introduce harm to customers in that it would potentially require such a conservative dispatch into the PJM market that overall* [off-system sales] *margins may be reduced and additional power purchases may be required just to serve the load of the Company.*"[86] But Dr. Pearce's claims are merely speculative since he did not quantify the potential harm to customers that could result. The record is left to wonder whether the potential harm is one dollar or one thousand dollars. Moreover, given Kentucky Power's significant off-system sales profits (approximately $50 million from January through April 2014),[87] the Company still will retain substantial profits after using Joint Intervenors' recommended approach and a change in dispatch protocol is unlikely. Finally, because Kentucky Power cannot unilaterally change the dispatch of its jointly owned Mitchell Units or the leased Rockport Units this is only a theoretical concern.

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[82] Wohnhas Rebuttal at 6:5-9 (citing RKW-1).
[83] Tr. at 65:23-66:2.
[84] KIUC Ex. 2.
[85] KIUC Ex. 2.
[86] Pearce Rebuttal at 4.
[87] Tr. at 85:3-6.

V. Similar To Kentucky Power's *"Fixed"* Environmental Costs, The Company's *"No Load"* Fuel Costs Should Be Fairly Allocated Between Native Load Customers And Off-System Sales Customers.

Though Kentucky Power's *"no load"* fuel costs are more aptly characterized as *"variable"* costs, Kentucky Power alleges that those costs are *"fixed."*[88] Even if the Commission accepts that characterization, the Company should not be excused from allocating the *"no load"* costs incurred to enable off-system sales to off-system sales.

Kentucky Power currently allocates *fixed* environmental costs to off-system sales customers in its monthly environmental surcharge filings. Fixed environmental costs include items such as low NO_X burners, continuous emissions monitors, etc. Kentucky Power's *fixed* environmental costs also include the *"no load"* portion of consumables (e.g. lime, limestone, reagent, etc.). The *"no load"* portion of environmental consumables is similar to its *"no load"* fuel costs.[89] Thus, while *"no load"* environmental costs are allocated to off-system sales customers in the environmental surcharge, *"no load"* fuel costs are charged entirely to native load customers in the FAC. Kentucky Power did not address this inconsistency.

All of the other utilities in Kentucky also assign *fixed* environmental costs to off-system sales."[90] The rationale behind this practice is that "*but for*" the *fixed* environmental costs, the off-system sales could not be made. In the environmental surcharge cases, the Commission repeatedly rejected Kentucky Power's argument that its *fixed* environmental compliance surcharge costs should be assigned only to its native load customers. The Commission stated:

> *Kentucky Power's generating facilities are currently used to make off-system sales and the cost of environmental improvements should be allocated to both retail and off-system sales. Kentucky Power has failed to demonstrate that the allocation of the surcharge to off-system sales would lower the margins on those sales to the point they would be uneconomical. To the extent that Kentucky Power is able to sell power off-system, proper cost allocation requires that the costs attributable to those sales, including environmental costs, be assigned to such sales, rather than being charged to retail sales.*[91]

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[88] Tr. at 47:22-23; Kentucky Power Response to KIUC First Set of Data Requests, Item No. 3.
[89] Tr. at 60:4-12; KIUC Ex. 2. Kentucky Power indicated that *"[a] portion of environmental consumable costs is also classified as 'no load costs' and is recovered through base rates or the environmental surcharge."* The other portion of those *"fixed" "no load"* environmental costs (i.e. costs of low NO_X burners, Continuous Emission Monitors, etc.) are allocated to Kentucky Power's off-system sales in the environmental surcharge.
[90] KIUC Ex. 2.
[91] Order, Case No. 96-489 (May 27, 1997).

The Franklin Circuit Court affirmed the decision of the Commission with respect to the allocation of *fixed* environmental compliance costs to off-system sales, ruling:

> *Because Kentucky Power's system is currently operated to supply wholesale sales for resale, a representative cost allocation must be made to these sales....Despite the huge blocks of power sold off-system, Kentucky Power maintains that Kentucky ratepayers should pay for 98.6% of all its new environmental costs. The Commission disagreed and ruled that costs should be allocated to the cost causer. The Commission held that there is some relationship between the energy consumed and the pollution caused by generating that energy. That decision is reasonable and should be affirmed.*[92]

And in 2001, when Kentucky Power again tried to allocate the vast majority of its *fixed* environmental costs to native load customers, the Commission again rejected such an approach, stating:

> *We further agree with the arguments of KIUC, which notes that significant levels of Kentucky Power's sales are made to off-system customers. Under these conditions, it is neither appropriate nor reasonable to allocate a greater share of Kentucky Power's environmental costs to its jurisdictional ratepayers, and in effect subsidize off system sales customers.*[93]
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> ***
>
> *The Commission has consistently rejected the argument that since a utility's generating facilities were installed to meet the needs of its jurisdictional customers, all environmental costs should be borne by those customers, even when the utility is also making off-system sales. Kentucky Power has offered nothing new here, but instead has simply repeated arguments which have already been rejected in this proceeding. Rather than not recovering the environmental costs assigned to off-system sales, regardless of whether these sales are to affiliates or non-affiliates, what will happen is that the margins made on the sale will be lower.*[94]

The Commission's rationale behind allocating a portion of Kentucky Power's *fixed* environmental costs to off-system sales customers should similarly apply in this case. Hence, even if Kentucky Power's theoretical *"no load"* fuel costs are characterized as *"fixed,"* the Company should be required to allocate a portion of those fuel costs to off-system sales customers. Kentucky Power's off-system sales during the review period could not have taken place if those *"no load"* fuel costs were not incurred. Accordingly, those costs should be treated similarly to Kentucky Power's *fixed* environmental compliance costs, i.e. fairly allocated between native load customers and off-system sales.

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[92] *Commonwealth of Kentucky v. Kentucky Public Service Commission*, Franklin Circuit Court, Consolidated Case Nos. 97-CI-114, 97-CI-01138, and 97-CI-01319 (April 30, 1998) at 19.
[93] Order, Case No. 2000-107 (February 8, 2001).
[94] Order, Case No. 2000-107 (February 8, 2001).

VI. Kentucky Power's Improper Fuel Cost Allocation Approach Differs From The Approaches Adopted By Every Other Utility In The Commonwealth.

No other utility in Kentucky (including EKPC and Duke, both of which are members of PJM) recognizes theoretical *"no load"* costs for fuel cost allocation purposes. Under EKPC's fuel cost allocation approach, *"[f]uel is allocated between native-load sales and off-system sales on a stacked cost basis. EKPC considers each hour of operation, determines if a sale was made from its system during that hour and then allocates the highest cost resource(s) to that sale for FAC purposes. The process of stacking and assigning the highest cost resources to off-system sales protects EKPC's native load from having no-load cost assigned inappropriately."*[95] EKPC *"does not track no-load cost and does not segregate no-load cost in its energy accounting for the fuel clause."*[96]

Duke described its fuel cost allocation process as follows: *"After the generating unit is dispatched, the actual energy costs consumed in a generating unit is allocated as either native or non-native based on a stacking process, allocating the lowest cost resources to native load first."*[97] Duke *"doesn't track how much of the total energy cost consumed in a month is related to no-load costs."*[98]

Both Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") *"use the After-the-Fact Billing ('AFB') model to determine the joint dispatch savings between LG&E and KU and to allocate the highest cost energy to off-system sales."*[99] While Kentucky Power may argue that one portion of LG&E/KU's fuel cost allocation approaches is similar to its *"no load"* approach, LG&E and KU *"[do] not utilize the term 'No load costs' in the dispatch and operation of [their] system[s]."*[100] The LG&E/KU situation is also unique. Post-merger, the two Companies began jointly dispatching their systems to achieve synergy savings. But each utility first dedicates its lowest fuel cost resources to its own native load. The joint dispatch only occurs

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[95] Kollen Testimony at 17:17-18:1 (citing EKPC Response to Commission Staff's Information Request Dated 08/13/014, Case No. 2014-00226, Request 29).

[96] Kollen Testimony at 18:1-18:2 (citing EKPC Response to Commission Staff's Information Request Dated 08/13/014, Case No. 2014-00226, Request 29).

[97] Kollen Testimony at 18:3-6 (citing Duke Kentucky Response to Staff First Set of Data Requests, Case No. 2014-00229, Staff-DR-01-029).

[98] Kollen Testimony at 18:6-8 (citing Duke Kentucky Response to Staff First Set of Data Requests, Case No. 2014-00229, Staff-DR-01-029).

[99] Kollen Testimony at 18:9-12 (citing LG&E Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00228, Question No. 25; KU Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00227, Question No. 25).

[100] Kollen Testimony at 18:12-13 (citing LG&E Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00228, Question No. 27; KU Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00227, Question No. 27).

after native load is satisfied. This created the need for special consideration of minimum segment fuel costs. Additionally, the end result of LG&E/KU's fuel cost allocation approaches is that higher fuel costs are allocated to off-system sales customers.[101] That is not the result under Kentucky Power's approach.

Big Rivers Electric Corporation ("Big Rivers") uses a form of system average cost allocation between native load and off-system sales, but *"[t]he no-load cost is a cost Big Rivers does not quantify because Big Rivers does not operate at a no-load state."*[102] According to Big Rivers *"there is no distinction made in the allocation of these theoretical costs between native-load and off-system sales."*[103]

The concept of *"no load"* costs is used by PJM for purposes of dispatching generating units. But the theoretical *"no load"* concept is not relevant and not appropriately applied to fuel cost allocation for FAC purposes, which is outside of PJM's purview.[104]

The uniform FAC regulation should be applied uniformly. This is especially true since unlike most other regulations, 807 KAR §5:056 does not allow for deviation upon a showing of good cause. For the first time, Staff and Intervenors now know how Kentucky Power treats *"no load"* fuel costs. The result is unreasonable and the practice should be ended.

VII. Kentucky Power's Improper Fuel Cost Allocation Approach Is Contrary To FERC Guidance Addressing How Fuel Costs Should Be Allocated.

Kentucky's FAC regulation, 807 K.A.R. 5:056, is modeled upon the FERC's fuel regulation, 18 C.F.R. §35.14.[105] 807 K.A.R. 5:056(3), provides that fuel costs recovered through the Kentucky fuel adjustment clause include a number of costs "*less…the cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.*" FERC's fuel regulation, 18 C.F.R. §35.14(a)(2), provides that fuel costs recovered through the FERC fuel adjustment clause include a

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[101] KIUC Ex. 11
[102] Kollen Testimony at 18:14-17 (citing Big Rivers Response to Commission Staff's Request for Information Date August 13, 2014, Case No. 2014-00230, Item No. 29).
[103] Kollen Testimony at 18:17-19:1 (citing Big Rivers Response to Commission Staff's Request for Information Date August 13, 2014, Case No. 2014-00230, Item No. 29).
[104] Kollen Testimony at 10:11-16.
[105] Order, Case No. 96-524 (February 9, 1999) at 7; Order, Case Nos. 94-461-A (July 15, 1999) at 11 ("*Reviewing the purpose of Order 517 – the Order which established FERC's FAC Regulation and upon which Administrative Regulation 807 KAR 5:056 is modeled.*").

number of costs *"less the cost of fossil and nuclear fuel recovered through all inter-system sales."* It therefore makes sense to examine how FERC interprets its fuel regulation and use that as guidance in interpreting Kentucky's fuel regulation.

The FERC has told Appalachian Power Company ("APCO"), a Kentucky Power affiliate company, that it *"believe[d] that it is both appropriate, and a common industry practice to assign the highest fuel cost to off-system sales, while lower fuel cost resources are reserved for the benefit of the APCO native load customers who, through their rates, provide for the construction and operation of the generating facilities."*[106] Although Company witness Allen attempts to characterize that FERC decision as addressing a *"very different"* issue than the allocation issue in this proceeding,[107] the general principle espoused in that case – that it is *"appropriate"* and *"common industry practice"* to assign the highest fuel costs to off-system sales and lower costs to native load customers – is applicable here. Moreover, the issue in that case was not as vastly different as Mr. Allen claims. There, two wholesale customers were concerned that the high costs of coal purchased from APCO's subsidiary would be passed through to them. Given that its practice ensured that the lowest fuel cost units should go to native load (all-requirements wholesale load), the FERC said that it would be appropriate if costs from the highest fuel cost units formed the basis for pricing of off-system sales.[108] Here, Joint Intervenors similarly advocate that costs from Kentucky Power's highest fuel costs units be assigned to off-system sales customers.

Additionally, in its Opinion No. 501, the FERC rejected a fuel cost allocation approach that assigned system average fuel costs to both native load and off-system sales (which is the approach taken by Big Rivers) because it forced native load customers to subsidize off-system sales by paying higher incremental fuel costs associated with those sales.[109] Thus, even an approach that allocates fuel costs *equally* to native load and off-system sales customers was not found satisfactory by the FERC.

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[106] Order Accepting Rates for Filing, Granting Intervention and Terminating Docket, Docket No. ER83-63-000, 21 FERC ¶61,309 (December 17, 1982) at 5; Rebuttal Testimony of William A. Allen (November 5, 2014)("Allen Rebuttal"), Ex. WAA-3 at 2.
[107] Allen Rebuttal at 5:22-6:2.
[108] Allen Rebuttal, Ex. WAA-3 at 2.
[109] Initial Decision, *Golden Spread Electric Cooperative, Inc. et al v. Southwestern Public Service Company*, 115 FERC ¶63,043 (May 24, 2006) at ¶132 ("Initial Decision"); Opinion No. 501, 123 FERC ¶61,047 (April 21, 2008) at ¶42-47; Allen Rebuttal, Ex. WAA-4 at 19-20.

Mr. Allen argues that Kentucky Power's fuel cost allocation approach is consistent with FERC Opinion No. 501.[110] However, Mr. Allen's argument hinges on whether FERC would consider Kentucky Power's *"no load"* costs to be *"incremental"* costs. Mr. Allen essentially argues that *after* 100% of Kentucky Power's *"no load"* costs are allocated to native load customers, the *remaining* fuel costs associated with off-system sales are the *"incremental"* costs that should be assigned to off-system sales customers.[111] In Mr. Allen's view, none of the *"no load"* costs are *"incremental"* costs as contemplated by FERC Opinion No. 501 and therefore those costs should not be allocated to off-system sales.

But FERC never uses the term *"no load"* costs nor does it distinguish *"no load"* costs from *"incremental"* costs in Opinion No. 501. FERC simply states that *"incremental"* costs associated with off-system sales should be assigned to off-system sales. Since moving from average cost pricing to incremental cost pricing resulted in FERC ordering a refund, it is probable that *"no load"* costs had to be included in FERC's definition of incremental cost. Therefore, in accordance with the rationale behind Opinion No. 501, those *"no load"* costs are *"incremental"* costs that should be assigned to off-system sales customers.

Mr. Allen also cites a 1995 case involving Tampa Electric Company in which the FERC found that other customers would not be harmed if one wholesale customer was charged *"incremental"* costs that could be lower than average costs pursuant to a proposed supply agreement.[112] Yet in that case, the FERC also found that other customers may actually end up paying lower rates if the agreement was approved because the agreement increased the demand charge to that wholesale customer.[113] Hence, there was a rate offset in that case to counterbalance any inequity. And again, the FERC did not clearly indicate that *"no load"* costs would not be considered *"incremental"* costs in that case.

In claiming that Kentucky Power's fuel cost allocation approach is consistent with FERC guidance, Company witness Allen also cites two audits that the FERC Division of Audits performed on the wholesale fuel adjustment clauses of two Kentucky Power affiliates, Ohio Power Company and Public Service Company of

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[110] Allen Rebuttal at 8:16-25.
[111] Allen Rebuttal at 8:18-23.
[112] Allen Rebuttal at 9:4-14; Ex. WAA-5.
[113] Allen Rebuttal, Ex. WAA-5 at 3.

Oklahoma.[114] Mr. Allen states that *"the audits resulted in no findings or recommendations related to the companies' wholesale fuel adjustment clauses,"* and reasons that the absence of such findings indicates that the fuel cost allocations adopted by those companies were consistent with FERC guidance.[115] But the audits that Mr. Allen cites occurred in 2008 and 2009, when the AEP Interconnection Agreement was in effect.[116] That is no longer the case. Further, the scope of those audits was limited. Those audits were not intended to be a comprehensive review of whether the fuel cost allocation methods were just and reasonable. The objective of both audits was merely to review the companies' compliance with FERC *"accounting and reporting"* requirements and *"validate the accuracy of the information filed with the Commission."*[117]

The rationale set forth in the FERC cases reinforces that Kentucky Power's fuel cost allocation approach is improper. Kentucky Power's fuel cost allocation approach harms native customers even more than the system average allocation approach rejected by the FERC. Instead of allocating the same fuel cost to native load and off-system sales, Kentucky Power assigns native load *above*-average fuel costs.

VIII. Kentucky's Fuel Adjustment Clause Regulation Allows For Refunds Outside Of A Base Rate Case.

Kentucky Power argues that the Commission cannot order a refund in this case because this is not a base rate proceeding, claiming that *"any decrease in the* [off-system sales] *margin credited against base rates must be balanced by a corresponding increase in the amount recoverable through base rates."*[118] This argument is inconsistent with the language of 807 K.A.R. 5:056 and Commission precedent. 807 K.A.R. 5:056 provides:

> *At six (6) month intervals, the commission will conduct public hearings on a utility's past fuel adjustments. The commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments it finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.*

[114] Allen Rebuttal at 4:8-5:2; Exs. WAA-1 and WAA-2.
[115] Allen Rebuttal at 4:21-5:2.
[116] Allen Rebuttal Ex. WAA-1 at 3 and WAA-2 at 3.
[117] Allen Rebuttal, Ex. WAA-1 at 6; Ex. WAA-2 at 7.
[118] Wohnhas Rebuttal at 11:10-14.

Hence, the language of the regulation requires the Commission to order refunds in proceedings such as this one if it finds that a utility has improperly calculated or applied its fuel adjustment charge. Because Kentucky Power has improperly applied its FAC, a refund must be issued in this case.[119]

The Commission has previously disallowed improperly collected fuel costs in the context of an FAC review proceeding. It did so with respect to KU/LG&E in the late 1990s and with respect to Big Rivers in the mid-1990s.[120] Even if the Commission's FAC regulation did not require a refund upon a finding of improper fuel costs, ordering such a result outside of a rate case would be permissible. In 2010, the Supreme Court of Kentucky held that rates could be changed outside of a rate case so long as the resulting rates are fair, just, and reasonable, stating:

> *We hold that so long as the rates established by the utility were fair, just and reasonable, the PSC has broad ratemaking power to allow recovery of such costs outside the parameters of a general rate case and even in the absence of a statute specifically authorizing recovery of such costs.*[121]

Hence, rate changes can occur outside of the context of a base rate proceeding. Kentucky Power's proposal to effectively rewrite the FAC regulation should be ignored.

IX. The Commission Should Require Kentucky Power to Refund $13.512 Million In Improperly Collected Fuel Costs, With Interest, To Native Load Customers And To Modify Its Fuel Cost Allocation For FAC Purposes Going Forward.

Because Kentucky Power's fuel cost allocation approach during the review period was improper, the Commission should order the Company to refund $13.512 million ($12.648 million in excessive fuel costs collected from native load customers from January 1, 2014 through April 30, 2014 plus $0.864 million in interest calculated at the Company's weighted average cost-of-capital). This refund amount is based upon the fuel costs that would have been allocated to native load customers during the January through April 2014 period using the

[119] Tr. at 32:21-23 and 36:10-14.
[120] *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Louisville Gas & Electric Company From November 1, 1998 to October 31, 1996*, Case No. 96-524, Order (February 9, 1999); *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company From November 1, 1997 to April 30, 1998*, Case No. 96-523-C; Order (July 21, 1999); *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1991 to April 30, 1992*, Order (July 21, 1994).
[121] *Kentucky Pub. Service Com'n v. Com. ex. rel. Conway*, 324 S.W. 3d 373, 374 (Ky. 2010).

same methodology used by EKPC and Duke.[122] The EKPC/Duke *"stacking"* approach ensures that the highest cost resources, including both generating unit fuel costs and purchase power costs, are allocated to off-system sales customers.[123] Further, EKPC, Duke, and Kentucky Power are all members of PJM.[124] It therefore makes sense to use the EKPC/Duke approach as the basis for how Kentucky Power's should have allocated fuel costs between native load customers and off-system sales customers during the review period.

Unlike Kentucky Power's approach, the EKPC/Duke hourly economic *"stacking"* approach results in higher fuel costs being allocated to off-system sales customers, though the difference in the costs allocated on a $ per MWH basis is not nearly as large as the difference between the costs allocated to native load customers and off-system sales customers under Kentucky Power's method. Over the period from January through April 2014, the range between the average price allocated to off-system sales customers and to native load customers are shown in the table below.[125]

Table 4

ALLOCATION $/MWh BY METHOD
Jan - Apr 2014

		Big Sandy	Mitchell	Rockport
	OSS	25.81	21.77	22.59
KPCO	NL	35.25	31.35	25.66
	Range	9.44	9.58	3.07
	OSS	31.38	30.59	25.53
EKPC	NL	30.42	26.53	24.50
	Range	0.97	4.06	1.04

Table 4 indicates that while the EKPC/Duke method allocates costs to native load customers that are lower than to off-system sales customers, the spread is much closer. For example, while there is a $9.44/MWH spread in average allocated costs under the Kentucky Power method for Big Sandy, there is a spread of just $0.97/MWH under the EKPC/Duke method. Thus, not only does the EKPC/Duke method more properly allocate

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[122] Hayet Testimony at 12:17-20.
[123] Hayet Testimony at 12:17-20.
[124] Hayet Testimony at 12:20-21.
[125] KIUC Ex. 9.

costs between native load customers and off-system sales customers, but it also results in the costs allocated to each being much closer to the unit's actual costs than under Kentucky Power's method.[126]

Using the EKPC/Duke fuel cost allocation methodology reveals that Kentucky Power overcharged its native load customers $12.648 million in excessive fuel costs from January through April 2014. This amounts to an allocation of 16% more fuel and purchase power costs to native load customers compared to what would have been allocated had Kentucky Power used the EKPC/Duke allocation approach.[127] A comparison of the monthly total fuel and purchase power amounts allocated to native load customers under both approaches, and the sum of each over the four-month period is demonstrated below.[128]

Table 5

ALLOCATION OF FUEL AND PURCHASE POWER COST

Month	KENTUCKY POWER COMPANY FILING	HOURLY RESTACK (EKPC METHOD)
Jan-14	$25,621,098	$21,920,710
Feb-14	$20,359,584	$18,251,010
Mar-14	$17,970,490	$16,331,433
Apr-14	$16,377,688	$11,177,599
Jan-Apr	**$80,328,860**	**$67,680,753**
	Savings using EKPC Method	**$12,648,107**
	% reduction	**16%**

The $12.648 million in excessive fuel costs collected by Kentucky Power should be refunded to its customers over a six-month period. The refund should also include the interest on the unjust and unreasonable FAC costs paid by customers, which should be calculated at Kentucky Power's weighted average cost-of-capital. This would result in a total refund of $13.512 million ($12.648 million excess fuel costs + $0.864 million in interest).

[126] Hayet Testimony at 15:4-16:3.
[127] Hayet Testimony at 17:7-10.
[128] Hayet Testimony at 17:1-6.

Alternatively, the Commission could adopt an alternative refund methodology of simply allocating *"no load"* costs to native load and off-system sales customers based upon megawatt hour sales. That would also represent a reasonable approach.[129]

Joint Intervenors note that their recommended refund is limited to the excessive fuel costs collected during the January 1, 2014 through April 30, 2014 period because the AEP Interconnection Agreement was still in effect for the first two months of the review period (November and December 2013).[130] The inter-company cost sharing arrangement set forth in the AEP Interconnection Agreement makes calculation of any excessive fuel costs collected in those months more difficult. Joint Intervenors maintain that any excessive fuel costs that Kentucky Power improperly allocated and charged to native load customers during the entire review period should be refunded to customers. But it would be more appropriate to address the calculation of any additional excessive costs during Kentucky Power's upcoming two-year FAC review case.

On an ongoing basis, Kentucky Power should also be required to adopt the fuel cost allocation approach used by EKPC/Duke for FAC purposes. As demonstrated above, economically *"stacking"* costs every hour and assigning the highest cost resources to off-system sales protects customers from disproportionate or unreasonably high FAC charges. This going-forward recommendation would also promote uniformity in how the FAC regulation is administered.

X. Kentucky Power Overstated Its Purchased Power Costs.

Both Staff and Kentucky Power acknowledged that the Company overstated its purchased power costs by incorrectly including the actual cost of non-economy purchased power expense in the FAC during the review period based on an erroneous interpretation of Commission orders for another utility. Instead, Kentucky Power should have re-priced the cost of this purchased power at the lower of actual cost or the cost of generation using the peaking unit equivalent methodology in accordance with the Commission's Order in Case No. 2000-00495-B addressing this issue specifically for the Company. Kentucky Power quantified the effects of this error at $0.084

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[129] *See* Tr. at 235:13-237:6 (referring to KIUC/AG's Response to Commission Staff First Requests for Information, Item No. 4).
[130] Tr. at 30:18-22.

million.[131] Consequently, the Commission should direct Kentucky Power to correct this error if the Company has not already done so.

CONCLUSION

WHEREFORE, for the reasons discussed above, the Commission should order Kentucky Power to refund \$13.512 million (\$12.648 million excess fuel costs + \$0.864 million in interest) to customers. The Commission should also require Kentucky Power to adopt the fuel cost allocation approach used by EKPC/Duke for FAC purposes on a going-forward basis.

Respectfully submitted,

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December 23, 2014

[131] Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 8.

ATTACHMENT

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)**

KENTUCKY POWER COMPANY
JANUARY 2014 ACTUAL
SOURCES AND DISPOSITION OF ENERGY FOR
FERC TYPE FUEL COST ADJUSTMENT CLAUSE

FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)

	Actual			Estimate w/o Mitchell			Notes	Incremental Cost (excl. No Load)			Notes
SOURCES OF ENERGY	MWH	AMOUNT ($)	$ / MWH	MWH	AMOUNT ($)	$ / MWH		MWH	AMOUNT ($)	$ / MWH	
1. NET GENERATION:											
Big Sandy	611,150	19,054,146	31.178	611,150	19,054,146	31.178	A	611,150	13,904,732	22.752	B
KP Share of Mitchell Unit 1	139,495	4,450,957	31.908	0	0	—	C				
KP Share of Mitchell Unit 2	219,535	6,403,183	29.167	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	135,241	3,274,172	24.210	135,241	3,274,172	24.210	A	135,241	2,959,199	21.881	B
UNIT POWER PURCHASE (AEG) ROCKPORT #2	128,673	3,080,784	23.943	128,673	3,080,784	23.943	A	128,673	2,769,784	21.526	B
TOTAL	1,234,094	36,263,242	29.385	875,065	25,409,102	29.037		875,065	19,633,715	22.437	
2. OTHER PURCHASES (CASH SETTLED):											
Third Party Power Purchase	75,824	7,100,285	93.642	125,888	16,261,141	129.171	D				
TOTAL	75,824	7,100,285	93.642	125,888	16,261,141	129.171					
3. TOTAL SOURCES (1+2)	1,309,918	43,363,527	33.104	1,000,953	41,670,243	41.631					
DISPOSITION OF ENERGY								Cost Impact on OSS			
4. OFF SYSTEM ALLOCATION OF SOURCES:											
Big Sandy	259,165	6,631,482	25.588	93,534	2,863,083	30.610	E	(165,631)	(3,768,399)	22.752	E
KP Share of Mitchell Unit 1	26,741	637,279	23.832	0	0	—	C				
KP Share of Mitchell Unit 2	48,331	1,149,152	23.777	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	57,057	1,262,859	22.133	20,592	464,980	22.581	E	(36,465)	(797,880)	21.881	E
UNIT POWER PURCHASE (AEG) ROCKPORT #2	49,753	1,090,060	21.909	17,956	405,604	22.589	E	(31,797)	(684,455)	21.526	E
Third Party Power Purchase	72,982	6,971,597	95.525	72,982	6,971,597	95.525	F				
TOTAL	514,028	17,742,429	34.516	205,064	10,705,264	52.205					
5. FUEL IDENTIFIED FOR NER (3-4)											
Big Sandy	351,985	12,422,664	35.293	517,616	16,191,063	31.280	G	165,631	3,768,399	(4.013)	
KP Share of Mitchell Unit 1	112,754	3,813,679	33.823	0	0	—	C	(112,754)	(3,813,679)	(33.823)	
KP Share of Mitchell Unit 2	171,204	5,254,030	30.689	0	0	—	C	(171,204)	(5,254,030)	(30.689)	
UNIT POWER PURCHASE (AEG) ROCKPORT #1	78,184	2,011,313	25.725	114,649	2,809,193	24.503	G	36,465	797,880	(1.223)	
UNIT POWER PURCHASE (AEG) ROCKPORT #2	78,920	1,990,724	25.225	110,717	2,675,180	24.162	G	31,797	684,455	(1.062)	
Third Party Power Purchase	2,842	128,688	45.278	52,907	9,289,544	175.584	G	50,065	9,160,856	130.305	
TOTAL	795,889	25,621,098	32.192	795,889	30,964,979	38.906	G	(0)	5,343,881	6.714	
6. TOTAL (4+5)	1,309,918	43,363,527	33.104	1,000,953	41,670,243	41.631		(308,965)	(1,693,284)	(33.104)	

Notes
- **A.** Assume no changes to Big Sandy or Rockport dispatch and cost.
- **B.** For Off System Sales (OSS) adjustment, reduce total fuel cost by no-load cost to determine total $/MWh incremental cost.
- **C.** Remove all fuel cost of Mitchell, including, as applicable, no-load and incremental fuel cost.
- **D.** Estimated increase in purchases required to serve internal load.
- **E.** Estimated reduction in MWhs and cost allocated to OSS from remaining units that must now be retained in order to serve internal load.
- **F.** Conservatively assume all purchases originally assigned to OSS were still allocated to OSS (i.e., none were retained for internal load needs).
- **G.** Remaining cost used to serve internal load without Mitchell. Still assigns Big Sandy and Rockport no load cost to internal load.

KENTUCKY POWER COMPANY

FEBRUARY 2014 ACTUAL
SOURCES AND DISPOSITION OF ENERGY FOR
FERC TYPE FUEL COST ADJUSTMENT CLAUSE

FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	Actual			Estimate w/o Mitchell			Notes	Incremental Cost (excl. No Load)			Notes
SOURCES OF ENERGY	MWH	AMOUNT ($)	$ / MWH	MWH	AMOUNT ($)	$ / MWH		MWH	AMOUNT ($)	$ / MWH	
1. NET GENERATION:											
Big Sandy	580,585	17,147,648	29.535	580,585	17,147,648	29.535	A	580,585	12,944,559	22.296	B
KP Share of Mitchell Unit 1	52,281	1,968,715	37.656	0	0	—	C				
KP Share of Mitchell Unit 2	249,044	7,335,766	29.456	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	94,746	2,459,416	25.958	94,746	2,459,416	25.958	A	94,746	2,232,981	23.568	B
UNIT POWER PURCHASE (AEG) ROCKPORT #2	95,240	2,539,066	26.660	95,240	2,539,066	26.660	A	95,240	2,297,417	24.122	B
TOTAL	**1,071,896**	**31,450,611**	**29.341**	**770,571**	**22,146,130**	**28.740**		770,571	17,474,957	22.678	
2. OTHER PURCHASES (CASH SETTLED):											
Third Party Power Purchase	57,851	3,210,163	55.490	97,799	6,519,956	66.667	D				
TOTAL	**57,851**	**3,210,163**	**55.490**	**97,799**	**6,519,956**	**66.667**					
3. TOTAL SOURCES (1+2)	**1,129,747**	**34,660,774**	**30.680**	**868,371**	**28,666,086**	**33.011**					
DISPOSITION OF ENERGY								Cost Impact on OSS			
4. OFF SYSTEM ALLOCATION OF SOURCES:											
Big Sandy	303,477	8,131,636	26.795	130,192	4,268,131	32.783	E	(173,285)	(3,863,504)	22.296	E
KP Share of Mitchell Unit 1	3,248	77,762	23.945	0	0	—	C				
KP Share of Mitchell Unit 2	34,638	866,167	25.006	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	49,491	1,167,489	23.590	21,232	501,474	23.619	E	(28,259)	(666,015)	23.568	E
UNIT POWER PURCHASE (AEG) ROCKPORT #2	38,437	895,533	23.299	16,489	366,114	22.203	E	(21,947)	(529,419)	24.122	E
Third Party Power Purchase	57,174	3,162,603	55.315	57,174	3,162,603	55.315	F				
TOTAL	**486,464**	**14,301,190**	**29.398**	**225,087**	**8,298,323**	**36.867**					
5. FUEL IDENTIFIED FOR NER (3-4)											
Big Sandy	277,108	9,016,012	32.536	450,393	12,879,517	28.596	G	173,285	3,863,504	(3.940)	
KP Share of Mitchell Unit 1	49,033	1,890,953	38.565	0	0	—	C	(49,033)	(1,890,953)	(38.565)	
KP Share of Mitchell Unit 2	214,406	6,469,599	30.175	0	0	—	C	(214,406)	(6,469,599)	(30.175)	
UNIT POWER PURCHASE (AEG) ROCKPORT #1	45,255	1,291,927	28.548	73,514	1,957,942	26.633	G	28,259	666,015	(1.914)	
UNIT POWER PURCHASE (AEG) ROCKPORT #2	56,804	1,643,532	28.934	78,751	2,172,952	27.593	G	21,947	529,419	(1.341)	
Third Party Power Purchase	677	47,560	70.266	40,625	3,357,352	82.642	G	39,948	3,309,793	12.376	
TOTAL	**643,284**	**20,359,584**	**31.649**	**643,283**	**20,367,763**	**31.662**	G	**(0)**	**8,179**	**0.013**	
6. TOTAL (4+5)	**1,129,747**	**34,660,774**	**30.680**	**868,371**	**28,666,086**	**33.011**		(261,377)	(5,994,688)	(30.680)	

Notes

A. Assume no changes to Big Sandy or Rockport dispatch and cost.
B. For Off System Sales (OSS) adjustment, reduce total fuel cost by no-load cost to determine total $/MWh incremental cost.
C. Remove all fuel cost of Mitchell, including, as applicable, no-load and incremental fuel cost.
D. Estimated increase in purchases required to serve internal load.
E. Estimated reduction in MWhs and cost allocated to OSS from remaining units that must now be retained in order to serve internal load.
F. Conservatively assume all purchases originally assigned to OSS were still allocated to OSS (i.e., none were retained for internal load needs).
G. Remaining cost used to serve internal load without Mitchell. Still assigns Big Sandy and Rockport no load cost to internal load.

KENTUCKY POWER COMPANY

MARCH 2014 ACTUAL
SOURCES AND DISPOSITION OF ENERGY FOR
FERC TYPE FUEL COST ADJUSTMENT CLAUSE

FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	Actual			Estimate w/o Mitchell			Notes	Incremental Cost (excl. No Load)			Notes
SOURCES OF ENERGY	MWH	AMOUNT ($)	$ / MWH	MWH	AMOUNT ($)	$ / MWH		MWH	AMOUNT ($)	$ / MWH	
1. NET GENERATION:											
Big Sandy	295,855	9,283,759	31.379	295,855	9,283,759	31.379	A	295,855	7,248,541	24.500	B
KP Share of Mitchell Unit 1	180,246	5,522,942	30.641	0	0	—	C				
KP Share of Mitchell Unit 2	250,451	6,347,642	25.345	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	143,800	3,191,497	22.194	143,800	3,191,497	22.194	A	143,800	2,782,252	19.348	B
UNIT POWER PURCHASE (AEG) ROCKPORT #2	138,629	3,081,680	22.230	138,629	3,081,680	22.230	A	138,629	2,677,832	19.317	B
TOTAL	**1,008,980**	**27,427,520**	**27.183**	**578,283**	**15,556,936**	**26.902**		578,283	12,708,626	21.976	
2. OTHER PURCHASES (CASH SETTLED):											
Third Party Power Purchase	42,406	2,740,092	64.616	179,532	14,101,348	78.545	D				
TOTAL	**42,406**	**2,740,092**	**64.616**	**179,532**	**14,101,348**	**78.545**					
3. TOTAL SOURCES (1+2)	**1,051,386**	**30,167,612**	**28.693**	**757,816**	**29,658,284**	**39.137**					
DISPOSITION OF ENERGY								Cost Impact on OSS			
4. OFF SYSTEM ALLOCATION OF SOURCES:											
Big Sandy	143,704	3,767,733	26.219	60,940	1,739,982	28.552	E	(82,764)	(2,027,750)	24.500	E
KP Share of Mitchell Unit 1	79,491	1,960,975	24.669	0	0	—	C				
KP Share of Mitchell Unit 2	74,136	1,738,603	23.451	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	53,897	1,207,738	22.408	22,856	607,150	26.564	E	(31,041)	(600,588)	19.348	E
UNIT POWER PURCHASE (AEG) ROCKPORT #2	45,385	997,263	21.973	19,246	492,349	25.582	E	(26,139)	(504,914)	19.317	E
Third Party Power Purchase	39,260	2,524,811	64.310	39,260	2,524,811	64.310	F				
TOTAL	**435,873**	**12,197,123**	**27.983**	**142,302**	**5,364,293**	**37.697**					
5. FUEL IDENTIFIED FOR NER (3-4)											
Big Sandy	152,151	5,516,027	36.254	234,915	7,543,777	32.113	G	82,764	2,027,750	(4.141)	
KP Share of Mitchell Unit 1	100,755	3,561,967	35.353	0	0	—	C	(100,755)	(3,561,967)	(35.353)	
KP Share of Mitchell Unit 2	176,315	4,609,040	26.141	0	0	—	C	(176,315)	(4,609,040)	(26.141)	
UNIT POWER PURCHASE (AEG) ROCKPORT #1	89,903	1,983,759	22.066	120,944	2,584,347	21.368	G	31,041	600,588	(0.697)	
UNIT POWER PURCHASE (AEG) ROCKPORT #2	93,244	2,084,417	22.355	119,383	2,589,331	21.689	G	26,139	504,914	(0.665)	
Third Party Power Purchase	3,146	215,281	68.431	140,272	11,576,536	82.529	G	137,126	11,361,256	14.098	
TOTAL	**615,513**	**17,970,490**	**29.196**	**615,514**	**24,293,991**	**39.469**	G	**0**	**6,323,501**	**10.274**	
6. TOTAL (4+5)	**1,051,386**	**30,167,612**	**28.693**	**757,816**	**29,658,284**	**39.137**		(293,571)	(509,328)	(28.693)	

Notes

- **A.** Assume no changes to Big Sandy or Rockport dispatch and cost.
- **B.** For Off System Sales (OSS) adjustment, reduce total fuel cost by no-load cost to determine total $/MWh incremental cost.
- **C.** Remove all fuel cost of Mitchell, including, as applicable, no-load and incremental fuel cost.
- **D.** Estimated increase in purchases required to serve internal load.
- **E.** Estimated reduction in MWhs and cost allocated to OSS from remaining units that must now be retained in order to serve internal load.
- **F.** Conservatively assume all purchases originally assigned to OSS were still allocated to OSS (i.e., none were retained for internal load needs).
- **G.** Remaining cost used to serve internal load without Mitchell. Still assigns Big Sandy and Rockport no load cost to internal load.

KENTUCKY POWER COMPANY

April 2014 ACTUAL
SOURCES AND DISPOSITION OF ENERGY FOR
FERC TYPE FUEL COST ADJUSTMENT CLAUSE

FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	Actual			Estimate w/o Mitchell			Notes	Incremental Cost (excl. No Load)			Notes
SOURCES OF ENERGY	MWH	AMOUNT ($)	$ / MWH	MWH	AMOUNT ($)	$ / MWH		MWH	AMOUNT ($)	$ / MWH	
1. NET GENERATION:											
Big Sandy	478,140	14,450,192	30.222	478,140	14,450,192	30.222	A	478,140	9,923,351	20.754	B
KP Share of Mitchell Unit 1	217,935	5,255,914	24.117	0	0	—	C				
KP Share of Mitchell Unit 2	150,979	4,294,641	28.445	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	109,938	2,790,045	25.378	109,938	2,790,045	25.378	A	109,938	2,421,334	22.025	B
UNIT POWER PURCHASE (AEG) ROCKPORT #2	90,024	2,352,528	26.132	90,024	2,352,528	26.132	A	90,024	2,048,937	22.760	B
TOTAL	1,047,016	29,143,319	27.835	678,102	19,592,764	28.894		678,102	14,393,623	21.226	
2. OTHER PURCHASES (CASH SETTLED):											
Third Party Power Purchase	55,635	2,042,947	36.721	72,359	2,715,910	37.534	D				
TOTAL	55,635	2,042,947	36.721	72,359	2,715,910	37.534					
3. TOTAL SOURCES (1+2)	1,102,651	31,186,266	28.283	750,461	22,308,674	29.727					
DISPOSITION OF ENERGY								Cost Impact on OSS			
4. OFF SYSTEM ALLOCATION OF SOURCES:											
Big Sandy	284,640	7,045,908	24.754	149,860	4,248,666	28.351	E	(134,780)	(2,797,242)	20.754	E
KP Share of Mitchell Unit 1	103,339	1,881,980	18.212	0	0	—	C				
KP Share of Mitchell Unit 2	67,373	1,207,183	17.918	0	0	—	C				
UNIT POWER PURCHASE (AEG) ROCKPORT #1	64,711	1,480,584	22.880	34,070	805,723	23.649	E	(30,641)	(674,861)	22.025	E
UNIT POWER PURCHASE (AEG) ROCKPORT #2	50,853	1,150,852	22.631	26,774	602,807	22.515	E	(24,079)	(548,045)	22.760	E
Third Party Power Purchase	55,582	2,042,073	36.740	55,582	2,042,073	36.740	F				
TOTAL	626,498	14,808,581	23.637	266,285	7,699,268	28.914					
5. FUEL IDENTIFIED FOR NER (3-4)											
Big Sandy	193,500	7,404,284	38.265	328,280	10,201,526	31.076	G	134,780	2,797,242	(7.189)	
KP Share of Mitchell Unit 1	114,596	3,373,934	29.442	0	0	—	C	(114,596)	(3,373,934)	(29.442)	
KP Share of Mitchell Unit 2	83,606	3,087,457	36.928	0	0	—	C	(83,606)	(3,087,457)	(36.928)	
UNIT POWER PURCHASE (AEG) ROCKPORT #1	45,227	1,309,460	28.953	75,868	1,984,322	26.155	G	30,641	674,861	(2.798)	
UNIT POWER PURCHASE (AEG) ROCKPORT #2	39,171	1,201,675	30.678	63,251	1,749,721	27.663	G	24,079	548,045	(3.014)	
Third Party Power Purchase	53	875	16.550	16,777	673,838	40.165	G	16,724	672,963	23.615	
TOTAL	476,153	16,377,686	34.396	484,176	14,609,406	30.174	G	8,023	(1,768,279)	-4.222	
6. TOTAL (4+5)	1,102,651	31,186,266	28.283	750,461	22,308,674	29.727		(352,190)	(8,877,592)	(28.283)	

Notes

A. Assume no changes to Big Sandy or Rockport dispatch and cost.
B. For Off System Sales (OSS) adjustment, reduce total fuel cost by no-load cost to determine total $/MWh incremental cost.
C. Remove all fuel cost of Mitchell, including, as applicable, no-load and incremental fuel cost.
D. Estimated increase in purchases required to serve internal load.
E. Estimated reduction in MWhs and cost allocated to OSS from remaining units that must now be retained in order to serve internal load.
F. Conservatively assume all purchases originally assigned to OSS were still allocated to OSS (i.e., none were retained for internal load needs).
G. Remaining cost used to serve internal load without Mitchell. Still assigns Big Sandy and Rockport no load cost to internal load.

KP Spot Market Energy - Day-Ahead Position

	Purchase MW	Cost
Jan	50,065	9,160,856.27
Feb	39,948	3,309,792.60
Mar	137,126	11,361,255.73
Apr	16,724	672,963.03
Total	**243,863**	**24,504,867.63**

No Load Costs
(provided in Staff 1-29)

	Jan Act	Feb Act	Mar Act	Apr Act
Big Sandy 1	448,955.90	400,241.53	499,222.21	276,695.13
Big Sandy 2	4,700,457.68	3,802,847.80	1,535,995.93	4,250,145.34
Mitchell 1 KP	1,730,564.38	707,862.36	1,706,322.71	1,530,893.45
Mitchell 2 KP	2,006,349.46	2,131,025.84	2,227,440.18	1,114,711.76
Rockport 1 KP AEG	314,973.52	226,435.36	409,244.66	368,710.18
Rockport 2 KP AEG	310,999.88	241,648.94	403,847.80	303,590.49
	9,512,300.81	7,510,061.84	6,782,073.49	7,844,746.34