**Duke Energy Kentucky**
**Case No. 2014-00454**
**Staff Second Set Data Requests**
**Date Received: March 11, 2015**

**STAFF-DR-02-005**

**REQUEST:**

Refer to page 16 of the Swez Testimony, lines 16-20, which discusses the reasons for including PJM billing line items 2370 and 2375 in the calculation of the Fuel Adjustment Clause ("FAC"). The Commission approved a settlement in Duke Kentucky's last electric base rate case[1] in which Duke Kentucky agreed to credit through its FAC make-whole revenues received from the Midwest Independent System Operators, Inc. ("MISO"), the regional transmission organization of which it was a member at that time.

a. Confirm that, since transferring its membership from MISO to PJM, Duke Kentucky has been crediting PJM billing line items 2370 and 2375 through its FAC because those billing line items are the PJM equivalent to the MISO make-whole payments. If this cannot be confirmed, explain.

b. Absent the settlement agreement in Case No. 2006-00172, explain whether Duke Kentucky believes PJM billing line items 2370 and 2375 should be included in the FAC calculation.

[1] Case No. 2006-00172, *An Adjustment of the Electric Rates of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky, Inc.* (Ky. PSC Dec. 21, 2006).

**RESPONSE:**

a. Since the transfer to PJM, Duke Energy Kentucky has been crediting the native portion of PJM billing line items 2370 and 2375 through its FAC because those billing line items are the PJM equivalent to the MISO make-whole payments.

b. Duke Energy Kentucky believes that PJM billing line items 2370 and 2375 credits should follow the generating unit's allocation. Thus, if in the after the fact costing allocation process, a generating unit was assigned to serve native load, any corresponding credits from PJM billing line items 2370 and 2375 should be allocated to native load. Conversely, if during the after the fact costing allocation process, a generating unit was assigned to serve non-native load, any corresponding credits from PJM billing line items 2370 and 2375 should be allocated to non-native load. It should be noted that even when allocated to non-native load, customers receive most of these credits through the Company's off-system sales profit sharing mechanism, Rider PSM.

   The Company believes that all PJM line item credits and charges should be included in Company rates through some combination of base rates, FAC, PSM, or other tracking mechanism.

**PERSON RESPONSIBLE:** John Swez/Lisa Steinkuhl/Scott Burnside

**Duke Energy Kentucky**
**Case No. 2014-00454**
**Staff Second Set Data Requests**
**Date Received: March 11, 2015**

**STAFF-DR-02-006**

**REQUEST:**

Refer to page 17 of the Swez Testimony, lines 19-22, which states that "other than the aforementioned operating reserve credits, the Company is only including charges and credits in its FAC during hours in which the Company is a net purchaser of power. This is a relatively simple approach when calculating and allocating PJM charges and credits." Provide the other approaches that could be used to allocate the PJM charges and credits.

**RESPONSE:**

The Company currently employs a stacking method that nets load and generation MWh on an hourly basis. When load is more than generation for an hour, the resulting difference in load MWh is considered purchased power. When generation is more than load for an hour, the resulting difference in generation MWh is considered off-system sales. As witness Swez states in his testimony on page 4, the LMP is the value of one additional megawatt of energy at a specific point on the electric grid and the LMP is composed of three components: the system energy price, the transmission marginal congestion price, and the marginal loss price. The LMP between the load zone and the generation stations are typically different and vary by the amount of congestion and losses present at each point.

For example, if in a given hour load is 600 MWh and generation is 500 MWh then purchased power is 100 MWh. The cost of the 100 MWh of purchase power contains PJM congestion and loss LMP components and is included in the FAC. However, the congestion and losses (difference in LMP) between 500 MWh of load and 500 MWh of generation are not being included in the FAC. The same is true if in a given hour load is 500 MWh and generation is 600 MWh. The 100 MWh of off-system sales contains PJM congestion and loss LMP components and the revenues from the off-system sales are included in the PSM. The congestion and losses (difference in LMP) between 500 MWh of load and 500 MWh of generation are not being included in the FAC or the PSM.

An alternative approach, using the same examples, would be to include the congestion and losses (difference in LMP) between 500 MWh of load and 500 MWh of generation in the FAC and to then also include various charges and credits related to congestion and losses, such as financial congestion management, transmission loss credit, and transmission congestion credit, in the FAC. However, the settlement approved by the Commission in Case No. 2006-00172 prevents Duke Energy Kentucky from utilizing this approach. As part of the revenue requirement approved in the settlement, the test year amount of congestion and losses between generation and load and the certain other related charges and credits were included in base rates and, therefore, the Company has not tracked such costs through the FAC or PSM or a transmission rider which was proposed in that case.

**PERSON RESPONSIBLE:** John Swez/Scott Burnside/William Don Wathen Jr.

**STAFF-DR-02-007**

**REQUEST:**

Refer to page 9 of the Direct Testimony of John A. Verderame ("Verderame Testimony") regarding PJM's proposed Capacity Performance construct.

a. State how PJM is proposing to define the requirements of a "Capacity Performance" asset.

b. Explain the penalties that are being proposed by PJM under the Capacity Performance construct.

**RESPONSE:**

a. PJM has proposed to define "Capacity Performance" as a capacity resource that must be capable of sustained, predictable operation that allows the resource to be available throughout the Delivery Year to provide energy and reserves whenever PJM determines an emergency condition exists.

PJM has also proposed to define "Base Capacity" as an interim product for the 2018/2019 and 2019/2020 delivery years while it transitions to 100% Capacity Performance for the 2020/2021 delivery year. "Base Capacity" is a capacity resource that is not capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year; however, the resource is capable of providing enhanced assurance to provide energy and reserves during hot weather operations in June through September.

Performance is assessed for each hour (or partial hour) that PJM declares the following actions:

- Pre-Emergency Load Management Reduction Action
- Emergency Load Management Reduction Action
- Primary Reserve Warning & reduction of Non-Critical Plant Load
- Maximum Emergency Generation, Maximum Emergency Generation Action Trans
- Emergency Voluntary Energy Only Demand Response
- Voltage Reduction Warning & Reduction of Non-Critical Plant Load
- Voltage Reduction Action & Curtailment of Non-Essential Building Load
- Manual Load Dump Warning
- Manual Load Dump Action

PJM qualifies further that Emergency Action means any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action, including but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

b. PJM proposes to assess performance, and impose non-performance charges, on capacity resources during emergency conditions. Penalties apply to both Base Capacity Resources and Capacity Performance Resources. Base Capacity Resources are exposed to non-performance charges only for performance during Emergency Actions in summer months and are calculated with a different non-performance charge rate.

Performance assessment hours will be delineated by PJM's declaration of the emergency actions identified above. PJM will compare a generation resource's expected performance against actual performance for each performance assessment hour. Demand resource performance will be evaluated if the resource is dispatched during a performance assessment hour. Performance will be evaluated on an hourly basis and each performance assessment hour will be calculated separately. Any shortfalls in performance will be subject to the non-performance charge. Excess (Bonus Performance) may be eligible for a performance credit.

The non-performance charge rate for Capacity Performance resources is based on the yearly Net Cost of New Entry (CONE) specific to the resource Locational Deliverability Area (LDA). The non-performance charge rate for Base Capacity Resources is based on the Weighted Average Resource Clearing Price specific to the resource LDA. A small divisor term is also applied, which PJM represents as an assumed 30 Emergency Action hours per year.

PJM has also made a provision, though the provision has been revised in the FERC comment and answer process, solely applicable to FRR entities such as Duke Energy Kentucky to elect to meet non-performance penalties physically by increasing generation commitments to the FRR plan submitted immediately subsequent to any non-performance assessment. The formula described below represents the most recent proposal by PJM during the comment process. The physical option is only available to FRR entities and there is no provision for bonus credits if the FRR entity elects the physical penalty option.

Specifically, the non-performance financial penalty formulas are:

**Non-Performance Charge Rate for CP Resources ($/MWh) = [LDA Net CONE ($/MW-day) * number of days in Delivery Year]/30**

As an example, if the utility LDA Net CONE = $300/MW-day, the Non-Performance Charge Rate = [$300/MW-day * 365 days]/30 = $3,650/MWh. For a unit that commits roughly 550 MWs of capacity to the PJM capacity construct and as proposed, would ultimately be subject to these non-performance penalties in its FRR plan, the HOURLY non-performance assessment would be $2,007,500. If the unit were to be unavailable for all of the expected 30 compliance hours, the penalty would be approximately $60,225,000.

**Non-Performance Charge Rate for Base Capacity Resources ($/MWhr) = [Weighted Average Resource Clearing Price ($/MW-day) for such resource * number of days in Delivery Year]/30**

As an example, if the utility LDA Weighted Average Resource Clearing Price = $120/MW-day, the Non-Performance Charge Rate = [$120/MW-day * 365 days]/30 = $1,460/MWh. For a unit that commits roughly 550 MWs of capacity to the PJM capacity construct and beginning with the 2018/2019 delivery year will be subject to these non-performance penalties in its FRR plan, the HOURLY non-performance assessment would be $803,000.

The non-performance physical penalty formulas are:

FRR Physical Repayment Option:

**Non-Performance Charge Rate for CP and Base Resources (MWs) = For each MW of Performance Shortfall in each month, the physical repayment is**

**equal to 0.166 MW of additional capacity in the Capacity Plan for the next Delivery Year.**

As an example, for a unit that commits roughly 550 MWs of capacity to the PJM capacity construct, an outage during a single performance assessment hour would obligate an FRR entity to commit an additional 91.3 MWs of unit specific capacity to its next year's final FRR Plan. A three month outage, during which there were at least one performance assessment hour in each month, would obligate the FRR entity to commit and additional 275 MWs of unit specific capacity.

PJM has also proposed a stop loss provision for total non-performance charge assessments. The stop loss limits maximum charges for calendar month and calendar year. The stop loss provision applies to both the financial and physical penalties, but is calculated differently.

Specifically, the Capacity Performance financial stop loss formulas are:

**Non-performance charge stop loss for Capacity Performance resources for a month = 0.5 * Net CONE* number of days in Delivery Year * UCAP commitment on the resource.**

**Non-performance charge stop loss for Capacity Performance resources for a year = 1.5 Net CONE * number of days in Delivery Year * UCAP commitment on the resource.**

As an example, committed as a Capacity Performance resource, the expected annual stop loss for roughly 550 MWs of UCAP would be 1.5*300*365*550 = $90,337,500.

The Base Capacity financial stop loss formula is:

**Non-performance charge stop loss for Base Capacity resources for a year = total capacity revenues due to resource for Delivery Year.**

As an example, committed as a Base Capacity resource, the expected annual stop loss for roughly 550 MWs of UCAP would be 120*365*550 = $24,090,000.

There is no proposed monthly stop loss for Base Capacity resources.

Non-performance charges will be distributed to resources of any type, even if not Capacity Resources, that performs above expectations. Bonus performance will be assigned a share of the collected Non-performance charge revenues based on the ratio of its bonus performance to total bonus performance from all resources for the same performance assessment hour.

The Capacity Performance physical stop loss formula is:

**Non-performance charge stop loss for Capacity Performance and Base Capacity resources for a month = 0.166 MW for each MW of Performance Shortfall.**

The physical penalty is assigned to the highest MW amount of shortfall during any single hour of a calendar month, subsequent shortfalls at or below that amount do not increase the penalty. Thus, the FRR Entity will be subject to, at most, 0.166 MW of additional capacity per MW of non-performance required for the next Delivery Year.

**Non-performance charge stop loss for Capacity Performance and Base resources for a year = 0.5 MW for each MW of Performance Shortfall.**

As an example, if an FRR entity with a 550 MW generator has a four-month forced outage during which there are at least one Performance Assessment Hour in each month, the annual stop loss will be reached in three months which would obligate the FRR entity to committing and additional 275 MWs of unit specific capacity. PJM does not assess non-performance charge in the fourth month.

**PERSON RESPONSIBLE:** John A. Verderame

**STAFF-DR-02-008**

**REQUEST:**

Refer to page 10 of the Verderame Testimony, lines 11-12, which state that "[t]he primary fuel at Woodsdale is natural gas delivered under the non-firm delivery contract." Explain whether Duke Kentucky is able to enter into a firm delivery contract for natural gas at the Woodsdale station. If so, has Duke Kentucky conducted any economic evaluation as to the cost of entering into a firm delivery contract for the Woodsdale station?

**RESPONSE:**

With the historically low capacity factor of the Woodsdale Station in PJM, to date Duke Energy Kentucky has not proposed incurring the additional ratepayer expense of firm gas transportation. However, since the introduction of PJM's Capacity Performance proposal, the Company is currently performing both feasibility and economic evaluations of options for the Woodsdale Station to meet the proposed compliance requirements. Those options include securing firm natural gas transportation and establishing an onsite secondary fuel supply with the capacity to provide the potential required extended run times. While the evaluations are ongoing and incomplete, at this time Duke Energy Kentucky has determined that there is no simple solution, and any option will likely require a long lead time for implementation.

Specifically regarding firm natural gas transportation for Woodsdale, indications from the potential gas pipeline transportation providers are that there is no incremental firm transportation available without expansion projects that would add required infrastructure. When FERC establishes Duke Energy Kentucky's ultimate obligation under this proposal and a timeline for compliance, the Company will be better able to propose the optimal solution to the Commission.

**PERSON RESPONSIBLE:** John A. Verderame

**STAFF-DR-02-009**

**REQUEST:**

Refer to page 11 of the Verderame Testimony, lines 16-23, which discuss the consequences to Duke Kentucky if the Federal Energy Regulatory Commission ("FERC") approves PJM's Capacity Performance plan.

a. Provide specifics regarding the reference to "potential upgrades at generation stations" to mitigate exposure to significant penalties.

b. Provide specifics regarding Duke Kentucky's reference to "significant and ongoing expenses" in order to meet the "no excuses availability requirements of Capacity Performance" (outside of capital expenditures).

c. State whether FERC's approval of PJM's plan would affect Duke Kentucky's FAC. If so, explain in detail how the FAC would be affected.

**RESPONSE:**

a. The PJM proposed policy regarding the assessment and materiality of non-performance penalties creates an extremely high threshold of generator performance. Strategies for meeting this threshold of performance can broadly be categorized into providing certainty of fuel availability, increasing reliability or "hardening" the generation assets, and upgrades that increase capacity that may provide a portfolio hedge against underperformance. In anticipation of exposure to these penalties, Duke Energy Kentucky is exploring all options that increase the likelihood of compliance with the requirements while minimizing the total cost of reliably serving our Customers. The Company is in the ongoing process of defining, categorizing, and prioritizing potential projects for detailed cost benefit analysis. Examples of potential upgrades being considered include:

- Pipeline infrastructure upgrade;
- Steam turbine upgrades;
- Dual fuel capability upgrades;
- Steam tube replacements;
- Air heater upgrades;
- Coal combustion monitoring upgrades;
- Critical spare part inventory upgrades; and,
- Burner enhancements.

The cost benefit analyses for these projects are incomplete at this time, and the ultimate viability and cost effectiveness of each is very dependent upon the outcome of the pending PJM FERC proceeding.

b. It is a certainty that in order to meet the performance criteria proposed an enhanced fuel strategy will necessarily be developed for the Woodsdale station. If securing firm gas transportation is determined to be the optimal solution to meet the Capacity Performance availability criteria, this expense could be significant and ongoing.

Duke Energy Kentucky does not expect to significantly alter its East Bend 2 coal procurement strategy in terms of providing enhanced availability of coal supply; however potential strategies to increase generation availability include consideration of changes to the specifications and types of coal procured for the plant. It is possible that altering coal specifications may improve reliability, but come at an increased fuel cost. These expenses, while cost effective, could be significant and ongoing.

c. The Capacity Performance construct will by definition primarily impact capacity prices in the PJM footprint which does not directly impact the FAC. However, in addition to the potential increased fuel and fuel related expenses mentioned above in parts a and b, it is possible that there will be collateral impacts in PJM energy markets that could impact the FAC and PSM. If the PJM proposal succeeds as designed, and higher rates of performance are actually realized during typical high load/high power price periods, it is possible that periods of scarcity pricing will diminish. The FAC could be positively impacted through reduced economic power purchase costs if Woodsdale is dispatched more or LMP's are lower, but could also be impacted through increased purchased power if the Woodsdale station is dispatched less frequently by PJM due to the availability to PJM of lower priced generation.

**PERSON RESPONSIBLE:** John A. Verderame

**STAFF-DR-02-010**

**REQUEST:**

In light of PJM's proposed Capacity Performance plan, has Duke Kentucky conducted any preliminary economic analysis comparing Duke Kentucky's continued election as a self-supply Fixed Resource Requirement entity against an election to participate in PJM's base residual auction? If so, provide a copy of any and all analysis conducted by Duke Kentucky.

**RESPONSE:**

A decision to transition from FRR to Reliability Pricing Model (RPM) fundamentally rests on whether the Company believes that customers would ultimately benefit from such a change. Much of the value from moving to RPM is a function of an entity's net generation position. In other words, the benefit of RPM lies in the ability to either monetize the market value of owned generation in excess of customer demand or to gain access to the market liquidity inherent in RPM in order to fill any shortfall in generation. In the RPM capacity auction construct, a Load Serving Entity (LSE) is charged for capacity needed to satisfy its load, including reserves. Generation owners sell their capacity, and to the extent it clears the auction, the generation owners receive revenues. When a generation owner is also the LSE, like Duke Energy Kentucky would be, any capacity revenues received through RPM auctions would thus be offset by the capacity payments customers would be exposed to in RPM. Length or shortfalls in capacity as compared to load thus translates into either a net revenue or net cost, respectively.

Since joining PJM, Duke Energy Kentucky has neither been materially long or short generation, had no immediate plans to build additional generation, and had found sufficient liquidity in the bilateral market to make any necessary small portfolio adjustments. Given the small net positions over the past few years, the economic analysis has been very straight forward and no formal economic analysis exists.

Secondary factors to consider in analyzing whether to leave the FRR construct include any difference in exposure to generation performance in the PJM tariff between FRR and RPM entities. Generally, prior to the Capacity Performance proposal, FRR and RPM entities have been subject to very similar performance requirements. The Capacity Performance proposal contains certain provisions that are unique to FRR entities, the most significant of which are the option to cure non-performance penalties with physical megawatts, and the exclusion from Capacity Performance requirements during the transition delivery years 2016/2017 and 2017/2018.

In its filing before FERC on the matter, Duke Energy Kentucky has argued for complete exemption from Capacity Performance for FRR entities and in the alternative, an exemption through the 2019/2020 delivery years. The ultimate applicability or timing of Capacity Performance obligations to FRR entities will likely be a key driver in any decision Duke Energy Kentucky makes to bring a proposal to transition to RPM before the Commission.

Beyond Capacity Performance issues, advocating for such a move is not something the Company would undergo lightly as such a move would incur a five year commitment to the RPM before Duke Energy Kentucky could move back to FRR status. Additionally, there is no current regulatory mechanism that reconciles capacity revenue and demand cost flows involved in order to make RPM status feasible.

One of the more significant risks identified with moving to RPM is potential exposure to the PJM Minimum Offer Price Rule (MOPR). Under the current PJM tariff, if Duke Energy Kentucky were to move to RPM the Woodsdale units would be subject to the rule. As such, PJM would prevent or mitigate Duke Energy Kentucky from offering below the PJM determined Offer Floor Price. If the unit did not clear the RPM auction because it was mitigated, ratepayers could be forced to pay twice for capacity, both for capacity procured from PJM and through base rates. It is possible that Duke Energy Kentucky could seek one of the current MOPR exemptions, but obtaining an exemption is a subjective determination made by PJM and PJM MOPR rule are always subject to change.

**PERSON RESPONSIBLE:** John A. Verderame

**STAFF-DR-02-011**

**REQUEST:**

Refer to Duke Kentucky's response to Item 2 of the Commission's February 5, 2015 Request for Information ("February 5, 2015 Request"). Duke Kentucky is proposing to use the expense month of July 2014 for the base fuel cost. The attachment to the response shows that the final fuel cost for July 2014 was $10,269,020.39. In its FAC filing made on December 15, 2014, for the expense month of November 2014, Duke Kentucky further revised July 2014 fuel costs to $10,441,539.66 (due to RTO resettlements). State why $10,269,020.39 is being used rather than $10,441,539.66.

**RESPONSE:**

The Company used total fuel costs of $10,269,020.39 rather than $10,441,539.66 because it resulted in a rate that is closer to the expected fuel rate projected for the next two-year period. If a total fuel cost of $10,441,539.66 is used, the rate would be $0.029606/kWh which is higher than both the originally proposed rate of $0.029117 and the expected fuel rate projected for the next two-year period.

The Company is not opposed to using a total fuel cost of $10,441,539.66 and a base fuel rate of $0.029606/kWh.

**PERSON RESPONSIBLE:** Lisa Steinkuhl