COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. TO BECOME A FULL PARTICIPANT IN THE PJM INTERCONNECTION LLC, BASE RESIDUAL AND INCREMENTAL AUCTION CONSTRUCT FOR THE 2027/2028 DELIVERY YEAR AND FOR NECESSARY ACCOUNTING AND TARIFF CHANGES	)))))))	CASE NO. 2024-00285

O R D E R

Duke Energy Kentucky, Inc. (Duke Kentucky) filed an application pursuant to KRS 278.218 and the Commission's December 22, 2010 Order in Case No. 2010-00203,[1] seeking to exit the Fixed Resource Requirement (FRR) plan and transition to full participation in PJM Interconnection LLC's (PJM) Reliability Pricing Model (RPM), consisting of an annual Base Residual Auction (BRA) and subsequent Incremental Auctions (IAs) per delivery year, beginning with the 2027/2028 delivery year.[2] Additionally, Duke Kentucky sought approval to amend Duke Kentucky's Profit Sharing Mechanism (Rider PSM); approval to reconcile the net capacity-related revenues and charges with customers receiving 100 percent of the benefit or costs of capacity outside of the current sharing percentages for other components of Rider PSM; approval for any necessary accounting treatment, waivers, and approvals necessary to effectuate the

[1] Case No. 2010-00203, *Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of Its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment* (Ky. PSC Dec. 22, 2010).

[2] Application at 1. The 2027/2028 delivery year takes place June 1, 2027, through May 31, 2028.

transition; and finally, for expedited treatment so that Duke Kentucky can transition to the RPM market as early as the 2027/2028 Delivery Year.[3]

PROCEDURAL HISTORY

On September 6, 2024, Duke Kentucky filed an application for approval to exit the FRR plan and to transition to full participation in the PJM RPM including any necessary and appropriate accounting treatment.

The Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General) was granted intervention on September 12, 2024.[4] The Commission entered a procedural schedule on September 18, 2024.[5] Duke Kentucky responded to three requests for information from Commission Staff.[6] Duke Kentucky responded to two requests for information from the Attorney General.[7] The Attorney General responded to one request for information from Duke Kentucky.[8] The Attorney General filed direct testimony on December 6, 2024, and Duke Kentucky filed rebuttal testimony on January 10, 2025. On January 13, 2025, Duke Kentucky filed a motion to submit the matter on the record; the Attorney General also requested the matter

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[3] Application at 1.

[4] Order (Ky. PSC Sept. 12, 2024).

[5] Order (Ky. PSC Sept. 18, 2024).

[6] Duke Kentucky's Response to Commission Staff's First Request for Information (Staff's First Request) (filed Oct. 18, 2024); Duke Kentucky's Response to Commission Staff's Second Request for Information (Staff's Second Request) (filed Nov. 15, 2024); Duke Kentucky's Response to Commission Staff's Third Request for Information (Staff's Third Request) (filed Jan. 3, 2025).

[7] Duke Kentucky's Response to the Attorney General's First Request for Information (Attorney General's First Request) (filed Oct. 18, 2024); Duke Kentucky's Response to the Attorney General's Second Request for Information (Attorney General's Second Request) (filed Nov.15, 2024).

[8] Attorney General's Response to Duke Kentucky's First Request for Information (Duke Kentucky's First Request) (filed Dec. 20, 2024).

be submitted on the record with the opportunity to file briefs. On February 27, 2025, the Commission issued a revised procedural schedule permitting the filing of briefs in this matter. On March 14, 2025, the Attorney General and Duke Kentucky filed their initial briefs. On March 21, 2025, both parties filed response briefs. This matter now stands for a decision on the record.

LEGAL STANDARD

KRS 278.218, states:

> (1) No person shall acquire or transfer ownership of or control, or the right to control, any assets that are owned by a utility as defined under KRS 278.010(3)(a) without prior approval of the commission, if the assets have an original book value of one million dollars ($1,000,000) or more and:
> The assets are to be transferred by the utility for reasons other than obsolescence; or
> The assets will continue to be used to provide the same or similar service to the utility or its customers.
> (2) The commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest.

The Commission has consistently interpreted "public interest" in the context of a transfer of utility assets as:

> [A]ny party seeking approval of a transfer of control must show that the proposed transfer will not adversely affect the existing level of utility service or rates that any potentially adverse effects can be avoided through the Commission's imposition of reasonable conditions on the acquiring party. The acquiring party should also demonstrate that the proposed transfer is likely to benefit the public through improved service quality, enhanced service reliability, the availability of additional services, lower rates or a reduction in utility expenses to provide present services. Such benefits, however, need not be immediate or readily quantifiable.[9]

[9] Case No. 2010-00203, Dec. 22, 2010 final Order at 2 (quoting Case No. 2002-00018, *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE Aktiengesellschaft and Thames Water Aqua Holdings GmbH* (Ky. PSC May 30,2002) at 7.)

Because the FRR construct requires Duke Kentucky to self-supply capacity and because the RPM construct is a market-based competitive auction construct, the transition will constitute a change in the functional ownership of a utility asset.

KRS 278.264 lays out the Commission's approval or denial of retirement of electric generating unit and establishes a rebuttable presumption against retiring fossil fuel-fired generating units. In relevant part:

> The commission shall not approve the retirement of an electric generating unit, authorize a surcharge for the decommissioning of the unit, or take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption created by this section is rebutted by evidence sufficient for the commission to find that:
>
> (a) The utility will replace the retired electric generating unit with new electric generating capacity that:
> 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
> 2. Maintains or improves the reliability and resilience of the electric transmission grid;
> 3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
> 4. Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service

BACKGROUND

Duke Kentucky is a utility engaged in the natural gas and electric business. Duke Kentucky generates electricity, which it distributes and sells, in the Boone, Campbell, Grant, Kenton, and Pendleton counties, Kentucky.[10] Duke Kentucky also purchases,

[10] Application at 2.

sells, stores, and transports natural gas in the Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton counties, Kentucky.[11] Duke Kentucky currently owns and operates approximately 1,076 MW of summer generating capacity, with East Bend Unit 2 Generating Unit (East Bend), a 600 MW coal-fired base load unit, supplying the portfolio's base load requirements.[12] Duke Kentucky meets its peaking requirements with the Woodsdale Generating Station (Woodsdale, a 476 MW six-unit natural gas-fire combustion turbine facility. [13] Duke Kentucky also has 9.3 MW of solar assets.[14] All of these resources, along with Duke Kentucky's demand response programs and potential bilaterial capacity purchases are utilized to meet the capacity load obligation from Duke Kentucky's customers under the FRR.[15]

PJM is a regional transmission organization (RTO) that "coordinates movement of wholesale electricity in all of part of 13 states and the District of Columbia."[16] PJM operates both a competitive wholesale electricity market, as well as managing an interconnected electricity grid for its member states.[17] PJM's RPM construct is a series of capacity auctions in which generation is bid into the market and utilities purchase necessary capacity for a delivery year in the future. Every delivery year has its own auctions and the majority of capacity is purchased in the first auction for a given delivery

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[11] Application at 2.

[12] The Direct Testimony of John Swez (Swez Direct Testimony) at 7.

[13] Swez Direct Testimony at 7.

[14] Swez Direct Testimony at 8.

[15] Swez Direct Testimony at 8.

[16] PJM - About PJM

[17] PJM - Who We Are

year. This first auction is called the BRA and occurs three years in advance of the intended delivery year.[18] Three scheduled IAs and a conditional IA, if needed, are also scheduled closer in time to the delivery year.[19] The subsequent IAs enable utilities to satisfy increases or decreases in the region's unforced capacity obligations because of higher or lower load forecasts or because a resource previously relied on will not be available.[20]

Members to PJM who do not participate in the RPM construct must participate in the FRR construct.[21] This alternative allows utilities to meet resource adequacy requirements outside of PJM's Capacity Market, as long as they can demonstrate that their resource adequacy plans (called FRR plans) will satisfy PJM's federally mandated reliability requirements.[22] Companies electing the FRR alternative can still participate in PJM's energy and ancillary service markets and can still sell energy outside PJM's markets.[23]

On December 22, 2010, the Commission allowed Duke Kentucky to transition from membership in Midcontinent Independent System Operator, Inc. (MISO), another RTO, to PJM, finding that Duke Kentucky's request to transfer functional control of its transmission assets from MISO to PJM was for a proper purpose and in the public interest

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[18] PJM Learning Center - Capacity Market/RPM FAQs.

[19] See PJM 2024/2025 RPM Third Incremental Auction Results at 1 (dated May 23, 2024). Incremental Auctions provide a mechanism for capacity suppliers to sell and purchase capacity and a means for PJM to adjust previously committed capacity levels due to Reliability Requirement increases or decreases.

[20] PJM Capacity Exchange User Guide at 6.

[21] See PJM Fixed Resource Requirement Alternative – Overview (dated Aug. 17, 2017).

[22] Securing Resources Through the Fixed Resource Requirement.

[23] Securing Resources Through the Fixed Resource Requirement.

subject to certain conditions.[24] However, the Commission directed Duke Kentucky to participate in PJM only through the FRR construct until Duke Kentucky specifically requested to participate in the RPM.[25] The Commission also directed Duke Kentucky to file a revised Rider PSM to provide that "effective January 1, 2012, the first $1 million in annual profits from off-system sales is allocated to ratepayers, with any profits in excess of $1 million split 75/25, with ratepayers receiving 75 percent and shareholders receiving 25 percent."[26] Since then, the Commission has authorized several amendments to the Rider PSM, including in Case No. 2017-00321, in which the Commission made a number of material changes, among them a change to the sharing mechanism percentage to provide customers with 90 percent of net proceeds and costs and eliminating the $1 million threshold.[27]

DUKE KENTUCKY'S ARGUMENTS

Move from FRR to RPM

Duke Kentucky argued that the transfer to full RPM auction participation is for a proper purpose and is in the public interest as it will allow Duke Kentucky to continue to provide reliable service to customers by providing sufficient generation capacity to meet customer demand, provides an opportunity for incremental value to customers, and

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[24] Case No. 2010-00203, Dec. 22, 2010 Order at 10.

[25] Case No. 2010-00203, Dec. 22, 2010 Order at 14.

[26] Case No. 2010-00203, Dec. 22, 2010 Order at 18.

[27] Case No. 2017-00321, *Electronic Application of Duke Energy Kentucky, Inc. For: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief* (Ky. PSC Apr. 13, 2018), final Order.

avoids risks that exist with continued FRR participation.[28] Duke Kentucky explained that these incremental risks include but are not limited to the following:

> 1) potential FRR plan penalties if the plan does not satisfy demand requirements; 2) avoiding the FRR capacity holdback limitation; 3) over procuring capacity due to the reserve margin differential between FRR and RPM during high-capacity prices; 4) the FRR minimal zonal capacity requirement; and 5) risk of limited bilateral capacity to meet an FRR plan.[29].

Duke Kentucky argued that the transfer to full RPM participation is in the public interest because the RPM best protects customers from the risk of a large, energy intensive customer locating in Duke Kentucky's service territory and requiring service prior to Duke Kentucky building or acquiring generation.[30] The transition to RPM, Duke Kentucky explained, could help insulate Duke Kentucky from the risk of an anemic bilateral capacity market due to announced retirements within the Duke Energy Ohio Kentucky (DEOK) zone and throughout PJM that limit its ability to procure additional or emergency capacity for its FRR plan.[31] Lastly, Duke Kentucky argued that PJM has contemplated changes to PJM's FRR construct that would negatively impact its participation as an FRR entity in the future.[32]

Duke Kentucky submitted a cost-benefit analysis that evaluated the differences between the participation in PJM as both an FRR and a full BRA auction participant in the

[28] Duke Kentucky's Initial Brief (filed Mar. 14, 2025) at 8.

[29] Duke Kentucky's Initial Brief at 10.

[30] Duke Kentucky's Initial Brief at 10.

[31] Duke Kentucky's Initial Brief at 10.

[32] Duke Kentucky's Initial Brief at 10.

form of what Duke Kentucky called a “heat map”.[33] Duke Kentucky’s analysis depicts the potential value of its generating portfolio in four capacity and energy pricing scenarios: (1) capacity exceeding demand with low prices; (2) demand exceeding capacity with low prices; (3) capacity exceeding demand with high prices; and (4) demand exceeding capacity with high prices.[34] Duke Kentucky’s analysis showed that transitioning to the full RPM participation was the most beneficial strategy in all scenarios except when Duke Kentucky’s capacity is in excess of demand coupled with a low auction clearing price.[35]

Duke Kentucky stated that it could be short on capacity for multiple reasons. First, a large energy intensive customer, such as a data center or large factory, could locate in Duke Kentucky’s service territory.[36] Next, a reduction in Duke Kentucky’s generation capacity value, as would be the case with a planned or forced unit retirement, would cause a short position. Duke Kentucky’s generation could also become devalued due to performance.[37] Finally, there is the stroke of the pen risk, where PJM could increase Duke Kentucky’s planning reserve margin or make other market rules or tariff changes that affect Duke Kentucky’s status or capacity position.[38]

Duke Kentucky explained that it considered several factors in analyzing the possible scenarios of market prices and capacity positions including the following:

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[33] Duke Kentucky’s Initial Brief at 11.

[34] Duke Kentucky’s Initial Brief at 11.

[35] Duke Kentucky’s Initial Brief at 12.

[36] Swez Direct Testimony at 13.

[37] Swez Direct Testimony at 13.

[38] Swez Direct Testimony at 13.

(1) the amount of capacity hold-back required of FRR members before they can sell any excess generation in PJM;

(2) Duke Kentucky's current required reserve margin as an FRR participant;

(3) the PJM capacity demand curve;

(4) the cost of replacement capacity if Duke Kentucky is short on capacity; and

(5) the relationships between the BRA and incremental capacity auction clearing prices.[39]

Duke Kentucky described that it also considered the risks and costs of PJM's penalties if Duke Kentucky's FRR plan is deficient, and replacement capacity is unavailable.[40] The FRR deficiency penalty is calculated at the shortfall amount multiplied by the greater of either the Gross Cost of New Entry (CONE) or 1.75 multiplied by Net CONE.[41] As an example, Duke Kentucky provided that the shortfall penalty of a 100 MW deficiency where there is no replacement capacity available, would be $16.2 million.[42] Duke Kentucky argued that the risk and exposure to FRR capacity deficiency penalties and the minimum internal zonal limitations are eliminated through the transition to full RPM auction participation.[43]

Duke Kentucky stated that, as of the date of the application, because of the current hold-back requirement of an FRR, Duke Kentucky must hold back 30 MWs of its available

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[39] Duke Kentucky's Initial Brief at 12.

[40] Duke Kentucky's Initial Brief at 12.

[41] Duke Kentucky's Initial Brief at 13.

[42] Duke Kentucky's Initial Brief at 13.

[43] Duke Kentucky's Initial Brief at 14.

capacity from the BRA.[44] However, once Duke Kentucky becomes a full RPM BRA participant, Duke Kentucky would be able to offer, and customers will receive the value of, all capacity cleared in the auction, the proceeds of which will flow through the Rider PSM.[45] Duke Kentucky estimated that had it been able to fully monetize all excess capacity in PJM's most recent completed BRA, an additional $2.364 million in incremental revenue would have been shared with customers.[46] Duke Kentucky explained that as a BRA participant, the reserve requirement changes based upon the price of capacity, meaning that because the amount of reserves needed for BRA participants depends upon PJM's sloped demand curve, a lesser amount of reserves would be procured by Duke Kentucky during periods of extremely high-capacity prices.[47]

Rider PSM Amendments

Duke Kentucky argued that amending the Rider PSM is for a proper purpose and is in the public interest and will enable it to net the costs with anticipated revenues of participating in the PJM RPM auction construct.[48] Duke Kentucky explained that, once its transition to RPM is complete, Duke Kentucky's PJM settlement statement will begin to include the charges and credits related to capacity auction participation to meet PJM's FERC-approved reliability requirements.[49] Duke Kentucky explained that amending Rider PSM to include all of the capacity-related transactions from PJM and bilateral

[44] Duke Kentucky's Initial Brief at 13.

[45] Duke Kentucky's Initial Brief at 13.

[46] Duke Kentucky's Initial Brief at 13.

[47] Duke Kentucky's Initial Brief at 13-14.

[48] Duke Kentucky's Initial Brief at 15.

[49] Duke Kentucky's Initial Brief at 15.

markets will ensure that customers are paying for and receiving the benefit of participation in the PJM RPM auction structure, including receiving the full value of generating resources used to serve customer demand.[50]

Duke Kentucky explained that once it transitions to a full RPM BRA auction participation it will begin receiving additional PJM billing line items (BLIs) charges and credits related to the auction.[51] Duke Kentucky stated that these BLIs are properly charged to participants in accordance with PJM's FERC-approved tariffs and are necessary for full participation.[52] Duke Kentucky argued that it is reasonable and proper for Duke Kentucky to include these charges and credits as proposed in the Application as they enable it to participate in PJM's auctions in accordance with PJM's rules and enable customers to receive the full value of its rate-based generation in the wholesale market capacity auctions.[53] The following new and tariffed capacity related BLIs include the following: 1600;1610; 1650; 1660; 1661; 1662; 1663; 1664; 1665; 1666; 2600; 2605; 2620; 2620; 2630; 2640; 2650; 2660; 2661; 2662; 2663; 2664; 2665; and 2666. A description of each of these BLIs is attached to this Order as Appendix A.

Duke Kentucky recommended that the Commission should authorize it to include these items for recovery, crediting, and netting through the Rider PSM. Duke Kentucky argued that, to do otherwise, would place unreasonable and uncompensated risks on it,

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[50] Duke Kentucky's Initial Brief at 16.

[51] Duke Kentucky's Initial Brief at 16.

[52] Duke Kentucky's Initial Brief at 16.

[53] Duke Kentucky's Initial Brief at 16.

deny it the ability to recover costs it incurs to provide service to customers, and would result in a regulatory taking that creates financial harm to the company.[54]

Duke Kentucky also requested that the Commission grant authorization to modify the Rider PSM sharing mechanism to separately account for the capacity portion of Rider PSM to net 100 percent of the charges and credits of participating in the capacity markets to customers.[55] Duke Kentucky explained that this modification ensures that customers will receive 100 percent of the net benefits or costs as a result of Duke Kentucky's participation in the RPM BRA and IAs and any costs or revenues in bilateral markets to meet PJM's FERC-approved reliability requirements.[56] Duke Kentucky stated that full RPM auction participation increases the value of the existing generating portfolio because Duke Kentucky will be able to sell 100 percent of its excess generating capacity, above customer demand, which Duke Kentucky is proposing to provide completely to customers.[57] Duke Kentucky argued that because it is proposing to give customers 100 percent of the capacity benefits, it is also symmetric and fair that customers also bear 100 percent of the costs.[58]

In terms of the energy market, Duke Kentucky stated that it is logical, proper, and in the public interest for Duke Kentucky to continue to share in the energy market revenues under the current 90/10 sharing percentage.[59] Duke Kentucky explained that

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[54] Duke Kentucky's Initial Brief at 18.

[55] Duke Kentucky's Initial Brief at 19.

[56] Duke Kentucky's Initial Brief at 19.

[57] Duke Kentucky's Initial Brief at 19.

[58] Duke Kentucky's Initial Brief at 19.

[59] Duke Kentucky's Initial Brief at 20.

energy markets are more volatile, changing hourly, with day-ahead and day of energy market commitments.[60] Duke Kentucky stated that it will continue to have managerial responsibility for the operation and dispatch of these assets, and it is logical for it to maintain a small share of the risk and benefit of managing that position and maximize their value by keeping the assets operating in an efficient, reasonable, and beneficial manner.[61]

ATTORNEY GENERAL'S ARGUMENTS

The Attorney General argued that, although he agrees a scenario could exist that transitioning into PJM's RPM construct may prove cost-effective for Duke Kentucky and its ratepayers in the short term, the Commission must also address PJM's capacity crisis.[62] The Attorney General implored the Commission to look not just at potential short-term benefits but also the long-term implications.[63] The Attorney General stated that as a vertically integrated state, Kentucky has been served well adhering to the practice of its utilities meeting native load with steel in the ground generation located within the Commonwealth.[64] The Attorney General argued that the Commission should require Duke Kentucky and Kentucky's other utilities to build new generation within the Commonwealth to meet capacity.[65]

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[60] Duke Kentucky's Initial Brief at 20.

[61] Duke Kentucky's Initial Brief at 20.

[62] Attorney General's Initial Brief (filed Mar. 14, 2025) at 12

[63] Attorney General's Initial Brief at 12.

[64] Attorney General's Initial Brief at 12.

[65] Attorney General's Initial Brief at 12.

The Attorney General made the following nine recommendations to address the above related concerns[66]:

- Duke Kentucky should be required to replace any retiring dispatchable capacity with owned or purchased pursuant to bilateral agreement, in-zone (preferably located in Kentucky), dispatchable capacity prior to the retirement of the capacity (Recommendation 1).

- Purchases through the BRA auction should be limited so that Duke Kentucky does not overly rely on the auction to satisfy capacity requirements. Duke Kentucky should be limited to purchase no more than nine percent of its annual capacity requirement through the BRA auction, and it should be required to bring its long-term capacity imbalance back into balance within a period of six years (Recommendation 2).

- As an alternative to the two conditions above, the Commission could consider approving Duke Kentucky's request to become an RPM entity, but also open a new docket to establish minimum capacity obligations for Kentucky-based RPM entities and set a goal for the new obligations to be in effect within one year of issuing its order in this docket (Recommendation 3).

- The Commission should limit the capacity and time period for recovery of net BRA and IA capacity purchase expense in PSM rates consistent with the underlying physical conditions addressed by Witness Kollen (Recommendation 4).

- The Commission should ensure there is no double recovery of capacity costs, once through base rates and then another recovery in whole or part through PSM rates… the Commission should impose a condition that requires a credit in the PSM rates to offset the continuing recovery of non-fuel operating expenses and purchased power expense in the base rates that are no longer incurred until base rates are reset in the future and exclude recovery of these costs. (Recommendation 5).

- The Commission should maintain the ten percent Duke Kentucky and ninety percent customers sharing allocation for all revenue and expense BLIs included in PSM rates, including the new BLIs (Recommendation 6).

- The Commission should ensure there are no ratemaking incentives to purchase capacity in the BRAs and IAs instead of acquiring new owned capacity and/or new or additional bilateral capacity purchases to replace retired owned capacity or terminated or reduced capacity purchases (Recommendation 7).

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[66] Attorney General's Initial Brief at 5-6.

- The Commission should exclude the compliance and other penalty expense BLIs from the PSM and thereby preclude Duke Kentucky from recovering these avoidable expenses through PSM rates (Recommendation 8).

- PSM should be modified so capacity revenues and costs are allocated based upon demand. (Recommendation 9).[67]

DUKE KENTUCKY'S RESPONSE TO THE ATTORNEY GENERAL'S ARGUMENTS

Duke Kentucky's response to Recommendation One is that placing such a geographic limiting condition on its transition is unnecessary as Kentucky law, specifically, KRS 278.264, already defines actions for the retirement of an electric generating unit.[68] Duke Kentucky stated that this recommendation places an unnecessary limitation on Duke Kentucky that may prove to be detrimental to customers.[69]

Duke Kentucky's response to Recommendation Two is that while Duke Kentucky does not anticipate relying solely on the PJM capacity auction construct to meet capacity needs, there could be times when it must rely more heavily upon the BRA/IA capacity purchases, in excess of capacity sales to meet customer demand, particularly if demand increases at a rate faster than Duke Kentucky can build or acquire interests in capacity.[70] Duke Kentucky also stated that in a scenario where a large customer data-center load comes online in Duke Kentucky's territory, Duke Kentucky may have no choice but to procure additional capacity, in excess of a nine percent threshold, to meet that demand and maintain reliability on the system.[71] Duke Kentucky argued that a six-year grace

[67] Kollen Direct Testimony at 11 and Attorney General's Reply Brief at 2.

[68] Duke Kentucky's Initial Brief at 23-24.

[69] Duke Kentucky's Initial Brief at 24.

[70] Duke Kentucky's Initial Brief at 26.

[71] Duke Kentucky's Initial Brief at 26-27.

period to cure capacity position imbalances is an unreasonable and unnecessary restriction on Duke Kentucky's ability to properly serve customers and meet their demand in the most economical manner.[72] Duke Kentucky stated that a six-year time limit may force Duke Kentucky to take actions that are more expensive or less beneficial to customers because it must operate within a six-year ticking clock to reach a capacity balance requirement.[73] Duke Kentucky also noted that it provides annual updates on its reserve margin, capacity purchases, and deficits as part of Admin Case No. 387[74] demonstrating that it is continually looking forward towards meeting its customers' demand and informing the Commission of its status.[75]

As to Recommendation Three, Duke Kentucky stated that it does not believe the Commission needs to take such action because a one-sized-fits all approach may not be the best policy for each of the PJM participants given their unique circumstances including generation portfolios, customer load, seasonal peaking, delivery zones, which all may impact capacity obligations.[76] Nonetheless, if the Commission decides to do so, Duke Kentucky stated that it will participate and would expect to offer similar arguments to those that have been presented in this proceeding.[77]

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[72] Duke Kentucky's Initial Brief at 27.

[73] Duke Kentucky's Initial Brief at 27.

[74] Administrative Case No. 387, *Electronic Review of the Adequacy of Kentucky's Generation Capacity and Transmission System* (KY. PSC Mar. 29, 2000).

[75] Duke Kentucky's Initial Brief at 27.

[76] Duke Kentucky's Initial Brief at 28.

[77] Duke Kentucky's Initial Brief at 28.

For Recommendation Four, Duke Kentucky argued that, although it agrees that a resource located in the DEOK zone is the best hedge for customers, a recommendation that limits its available choices for additional resources to the DEOK zone could cause customers additional costs and is unnecessary.[78] Duke Kentucky strongly disagreed with the recommendation that replacement capacity be limited in any way or amount to bilateral purchases from assets within the DEOK zone.[79]

For Recommendation Five, Duke Kentucky stated it was premature to address these issues now, as these issues can easily and more appropriately be addressed by the Commission, if, and when, it seeks approval to retire a generating asset.[80] Duke Kentucky argued that Mr. Kollen, witness for the Attorney General, is only partially correct in his assumptions, is mistaken on how Duke Kentucky recovers costs of capacity and bilateral capacity purchases, and overlooks the fact that Duke Kentucky may not have fully recovered its costs already incurred in providing service prior to a future generating unit's retirement.[81]

For Recommendation Six, Duke Kentucky argued that limiting it to 90 percent recovery would be a fundamental departure from established rate making policy meaning customers would not pay their full costs to serve their given demand in some situations.[82] Duke Kentucky argued that, since customers should pay the full costs of serving them, including the provision of adequate capacity with sufficient reserves to meet customers'

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[78] Duke Kentucky's Initial Brief at 28-29.

[79] Duke Kentucky's Initial Brief at 29.

[80] Duke Kentucky's Initial Brief at 32.

[81] Duke Kentucky's Initial Brief at 30.

[82] Duke Kentucky's Initial Brief at 33.

demand, it is fair that customers should also receive 100 percent of the benefits, or revenues for that capacity.[83]

For Recommendation Seven, Duke Kentucky agreed that there should be no ratemaking incentive favoring one method of satisfying its capacity requirement over another; however, it disagreed that conditions should be put in place that unreasonably restrict its ability to manage its portfolio, limit its ability and flexibility to meet customer demand in capacity needs in the most reasonable, reliable, and efficient manner.[84] Duke Kentucky argued that it would be unreasonable for the Commission to place unnecessary restrictions on Duke Kentucky or to shift additional risks to the company when it is seeking to do what is in the customers' best interests.[85]

For Recommendation Eight, Duke Kentucky argued that the Commission should reject the recommendation to exclude Compliance and Penalty Expense BLIs from Rider PSM because the recommendation is based upon a faulty premise, by PJM's use of the words "compliance penalty," "deficiency," and "test failure", that Duke Kentucky did something wrong or acted imprudently.[86] Additionally, Duke Kentucky explained that the listing of PJM BLIs is asymmetric and one-sided in the Attorney General's testimony, taking the credits and benefit side provided by the BLIs but inappropriately allocating the corresponding "charging" BLIs to Duke Kentucky.[87] Duke Kentucky argued that providing customers with all of the upside and the company with all of the downside of capacity

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[83] Duke Kentucky's Initial Brief at 33.

[84] Duke Kentucky's Initial Brief at 35.

[85] Duke Kentucky's Initial Brief at 35.

[86] Duke Kentucky's Initial Brief at 36.

[87] Duke Kentucky's Initial Brief at 36.

market risks is unreasonable and untenable, thereby making the transition to RPM harmful to Duke Kentucky.[88] Duke Kentucky also stated that customers have clearly benefitted from this additional revenue sharing percentage since 2018 and it would be unreasonable to now say customers only receive benefits and do not bear any risks simply because of a change in PJM market participation.[89]

As to Recommendation Nine, Duke Kentucky is not opposed to changing the allocation of capacity revenues and costs included in the PSM to be based on demand consistent with how capacity costs are allocated in base rates.[90] However, Duke Kentucky did not agree that those capacity revenues and costs should be billed on a demand basis and that it should continue billing residential and non-residential customers based on kWh.[91] Duke Kentucky argued that maintaining the current billing will allow it and the Commission time to study how any change in billing determinants will impact certain customer classes.[92]

DISCUSSION AND FINDINGS

Based on the discussion below, the evidence in the record, and being otherwise sufficiently advised, the Commission finds that Duke Kentucky's proposal to switch from PJM's FRR construct to its RPM construct is reasonable and should be approved. For the reasons explained below, based on the evidence in record, and being otherwise sufficiently advised, the Commission approves, in part, and denies, in part, the requested

[88] Duke Kentucky's Initial Brief at 36.

[89] Duke Kentucky's Initial Brief at 39.

[90] Duke Kentucky's Initial Brief at 40.

[91] Duke Kentucky's Initial Brief at 40.

[92] Duke Kentucky's Initial Brief at 40.

modifications to Duke Kentucky's Rider PSM. Generally, at issue is Duke Kentucky's request to include certain billing line items (BLI) in the Rider PSM as well as Duke Kentucky's request to reconcile the net capacity-related revenues and charges with customers receiving 100 percent of the benefit or costs of capacity outside of the current sharing percentages for other components of Rider PSM.

With the Commission's approval in this case, Duke Kentucky will become the second electric utility in the Commonwealth to participate in PJM using the RPM construct. In 2012, East Kentucky Power Cooperative, Inc. (EKPC) filed its application to join PJM.[93] Unlike Duke Kentucky, EKPC determined that it intended to join PJM as an RPM entity and presented evidence to support its position.[94] In granting EKPC's request to join PJM as an RPM participant, the Commission relied in part on the idea that being an RPM member meant meeting a lower planning reserve requirement which had the potential to produce additional revenue because excess capacity can be sold at the PJM BRA clearing price.[95] Moreover, joining as an RPM member also eliminated the FRR's requirement to hold back an additional 3 percent of capacity as a reserve requirement which again had the potential to produce additional revenue.[96]

These two similarities between Duke Kentucky's application and the 2012 EKPC application are certainly not dispositive or even sufficient to support approving the RPM

[93] Case No. 2012-00169, *Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC* (Ky. PSC Dec. 20, 2012).

[94] Case No. 2012-00169, Dec. 20, 2012 Order at 13–14.

[95] Case No. 2012-00169, Dec. 20, 2012 Order at 6, 13–14.

[96] Case No. 2012-00169, Dec. 20, 2012 Order at 14.

construct in this case on its own. However, EKPC's case is nonetheless instructive given the relative novelty of the issue.

Duke Kentucky has provided evidence in this case that transitioning to the RPM construct has the potential to produce similar results. In Mr. Swez's testimony, he stated that, as an FRR entity, Duke Kentucky is currently limited in the amount of excess capacity that may be sold at the capacity auction because it is required to hold back the lesser of 450 MW or a 3 percent collar.[97] Duke Kentucky is not allowed to sell this excess capacity until the third incremental auction; however, the RPM construct does not require the hold back.[98] Assuming that capacity prices remain elevated, and that Duke Kentucky continues to have excess capacity, the cost of remaining an FRR entity could exceed $4 million annually.[99] Additionally, given the elevated cost of purchasing capacity, and the likelihood that it will remain elevated, Duke Kentucky stands to benefit from a lower required reserve margin because PJM participants purchase reserve capacity on a sloped demand curved keyed off the price of capacity for any given year which lowers the required reserve margin as the capacity price increases.[100]

<u>The RPM Construct</u>

As Duke Kentucky noted through the testimony of Mr. Swez, the FRR construct has been historically more beneficial Duke Kentucky.[101] However, as the application states, and Mr. Swez detailed, Duke Kentucky's recent cost-benefit analysis comparing

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[97] Swez Direct Testimony at 7.

[98] Swez Direct Testimony at 7.

[99] Swez Direct Testimony at 16.

[100] Swez Direct Testimony at 21.

[101] Swez Direct Testimony at 10.

the FRR and RPM constructs has changed its position. Driven largely by the vastly increased cost of capacity and growing demand, Duke Kentucky argued generally that the RPM construct has the potential to produce more revenue because the company has excess capacity to sell into the market and likewise, even if it becomes capacity short, the penalties under the RPM construct will be less impactful than if Duke Kentucky was in the same position but remaining an FRR entity.[102] The reduced penalties were modeled as the difference between procuring additional capacity under the RPM auctions and the cost of bilateral contracts and penalties under the FRR plan.[103] Because the BRA results were used as the starting point for the bilateral capacity purchases and Net CONE was used for the starting point for the penalties, the cost of securing additional capacity was lower under the RPM construct.[104]

Duke Kentucky illustrated its arguments through Mr. Swez's heatmap matrix which visualizes the impact that market prices and Duke Kentucky's capacity position has on whether it will be beneficial to transition to RPM participation.[105] The heatmap is evaluated by separating it into quadrants which are categorized as follows:

1. Low BRA market capacity price, long capacity position.
2. Low BRA market capacity price; short capacity position.
3. High BRA market capacity price, long capacity position.
4. High BRA market capacity price, short capacity position.

[102] Swez Direct Testimony at 11.

[103] Swez Direct Testimony at 18.

[104] Swez Direct Testimony at 18.

[105] Swez Direct Testimony, Attachment JDS-1 at 3. Included as Appendix B to this Order.

Historically, Duke Kentucky has remained in the first quadrant as capacity prices have remained low and Duke Kentucky has been capacity long and consequently enjoyed being an FRR participant.[106] However, as capacity prices increase, the lost revenue from the required 3 percent capacity hold back will become more noticeable.[107] Moreover, as the heat map attached as Appendix C shows, in the worst-case scenario modeled (high BRA clearing price of $525 per MW-Day and 10 percent capacity shortfall), the RPM construct will still result in net savings to customers when compared to the applicable FRR penalties for the same capacity shortfall.[108]

While many of the benefits and risks discussed by Duke Kentucky are currently speculative, Duke Kentucky's assumption that capacity prices will continue to remain elevated, if not sharply increase, appears reasonable. PJM prices have historically remained relatively low but, beginning with the 2025/2026 delivery year, PJM prices will increase astronomically: jumping from a DEOK clearing price of $96.24 per MW-Day in the DEOK zone for the 2024/2025 delivery year to $269.92 per MW-Day for the 2025/2026 delivery year.[109] Additionally, neither Duke Kentucky nor the Attorney General have presented evidence that the cost of capacity will decrease any time soon. This is, at least in part, because of impending load growth locating in the PJM footprint and the anticipated retirement of approximately 40,000 MW of generation by 2030.[110] Given the

[106] Swez Direct Testimony at 14.

[107] Swez Direct Testimony at 16.

[108] Swez Direct Testimony, Attachment JDS-1 FRR/RPM Analysis.

[109] Swez Direct Testimony at 27.

[110] PJM's 2023 Regional Transmission Expansion Plan (dated Mar. 7, 2024) at 26. (https://www.pjm.com/-/media/DotCom/library/reports-notices/2023-rtep/2023-rtep-report.pdf). *See also*, Hayet Direct Testimony at 19; Energy Transmission in PJM: Resource Retirements, Replacements & Risks

likelihood that load growth will occur more quickly than replacement and additional generation can become operational, the resulting asymmetry will almost surely continue to place further strain on the PJM footprint. These factors all support the reasonable assumption that capacity prices have the potential to remain high, with meaningful price increases possible. Consequently, while Duke Kentucky's analysis supports the transition to the RPM construct, relying on the marketplace to supply capacity in excess of its generation capabilities for any meaningful length of time will expose ratepayers to the real risk of increased bills.

The strain on the broader PJM footprint is evidence that the Commission's long-standing preference for steel-in-the-ground generation is prudent and necessary to protect ratepayers. Therefore, the Commission is concerned by Duke Kentucky's projected timeline to construct, and make operational, new generation. For example, Duke Kentucky stated that it believes it will need eight years to bring a new natural gas combined cycle unit (NGCC) online.[111] Assuming the timeline is accurate, Duke Kentucky will need to be remarkably vigilant regarding the health of its current generating plants and act decisively to ensure that it protects its ratepayers. The mere fact that Duke Kentucky with this approval can fully utilize the BRA/IA markets does not obviate its obligation to ensure that it has sufficient generation to meet the needs of its customers, nor will the Commission look kindly on Duke Kentucky's sustained reliance on the market in lieu of constructing least cost, most reasonable generation.

(dated Feb. 24, 2023) at 3. https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

[111] Duke Kentucky's Reply Brief at 11.

The Attorney General's Proposed Guardrails

Having found that Duke Kentucky has presented sufficient evidence to transition to the RPM construct, the Commission next considers the proposed guardrails presented by the Attorney General. As previously stated, the Attorney General does not object to Duke Kentucky's proposal to join the RPM construct. Instead, the proposed guardrails are intended to mitigate ratepayer risks associated with the increased flexibility of the RPM construct. In total, the Attorney General presented the Commission with nine substantive recommendations.[112] Of the nine recommendations, three are directly relevant to this discussion. Those are:[113]

> - [Duke Kentucky] should be required to replace any retiring dispatchable capacity with owned or purchased pursuant to bilateral agreement, in-zone (preferably located in Kentucky), dispatchable capacity prior to the retirement of the capacity. (Recommendation One)
>
> - Purchases through the BRA auction should be limited so that [Duke Kentucky] does not overly rely on the auction to satisfy capacity requirements. [Duke Kentucky] should be limited to purchase no more than nine percent of its annual capacity requirement through the BRA auction, and it should be required to bring its long-term capacity imbalance back into balance within a period of six years. (Recommendation Two)
>
> - As an alternative to the two conditions above, the Commission could consider approving [Duke Kentucky]'s request to become an RPM entity, but also open a new docket to establish minimum capacity obligations for Kentucky based RPM entities and set a goal for the new obligations to be in effect within one year of issuing its order in this docket. (Recommendation Three)

[112] *See* Attorney General's Initial Brief at 5–6.

[113] Attorney General's Initial Brief at 5.

Recommendation One

Regarding the first recommendation, the Commission agrees with both parties that the legislature has already established the appropriate process for retiring dispatchable fossil fuel fired generation in KRS 278.264 and finds that no further requirements from the Commission are necessary. While the Commission broadly agrees with the Attorney General's preference that generation be located within the DEOK zone, and the Commonwealth specifically, a preemptive order or requirement to locate new generation within the DEOK zone is premature. Because utilities are required to satisfy the CPCN standard, in which the principle of a least-cost, most reasonable alternative resource is embedded, a utility must consider the options available to it. Instead, the Integrated Resource Plan process generally, and the CPCN process, specifically, are the appropriate procedural vehicles to safeguard ratepayers.

Recommendation Two

The Commission again agrees with the Attorney General's concerns regarding long-term reliance on the PJM market to satisfy capacity deficits. However, the Attorney General's second recommendation is also premature. Duke Kentucky currently has excess capacity and will benefit, at least in the near-term, from the greater ability to sell that capacity into the PJM market. Additionally, the Commission finds Duke Kentucky's concerns about establishing a bright line limit on the percentage of any hypothetical deficit it could purchase on the PJM market convincing in so far as Duke Kentucky should be able to quickly respond to secure the locating of potential large customers such as manufacturing plants, commercial clients, or even data centers.

Kentucky utilities must not otherwise inhibit the potential for meaningful investment in the Commonwealth and its workforce. Moreover, while the Attorney General's concerns are legitimate, and the Commission urges Duke Kentucky to consider them seriously, the harms involved are not limited to RPM participation. Indeed, it is entirely possible to be an FRR member while still unreasonably exposing customers to market volatility.

Recommendation Three

As for the Attorney General's third recommendation, the Commission does not currently believe that opening a new case on the Commission's docket to establish minimum capacity obligations is necessary. Instead, the Commission believes that requiring Duke Kentucky to regularly provide the Commission with reports detailing how it satisfies its capacity needs as an RPM member, and the costs associated with securing that capacity broken down by each relevant PJM BLI. The information will give the Commission an opportunity to understand whether Duke Kentucky is acting prudently while retaining maximum flexibility in the short-term to take advantage of its long capacity position in the market. Of course, if the Commission, or the Attorney General for that matter, identifies any concerning trends the Commission will strongly consider this recommendation in addition to any investigation or other proceeding which could be appropriate in such a scenario.

Therefore, Duke Kentucky should file a report following the disposition of this case, beginning after the conclusion of the first BRA auction in which Duke Kentucky participates as an RPM member, which details specifically how much capacity Duke Kentucky bid into the BRA auction and how much it purchased, making sure to include the percentage of deficit or surplus. Additionally, every quarter, beginning with the conclusion of the first full quarter that Duke Kentucky participates as an RPM member, Duke Kentucky should file a report stating whether, and how much, capacity Duke Kentucky purchased or bid in the IA. The Commission will not look favorably on any trends indicating longer-term reliance on the market for capacity absent reasonable justification.

Based on the above discussion, and the evidence in the record, and being otherwise sufficiently advised, the Commission finds that Duke Kentucky has adequately demonstrated that transitioning to the RPM construct is for a proper purpose and in the public interest.

<u>PSM Rider Amendments</u>

Having found that Duke Kentucky may transition to the RPM construct, the Commission now considers Duke Kentucky's proposed amendments to the Rider PSM. From the outset, the Commission notes, that the findings related to BLI exclusions from Rider PSM are not to be construed as a final statement regarding the reasonableness of a particular cost. Items deemed not eligible for the Rider PSM can still be appropriately dealt with in an application for a base rate adjustment or any other proceeding which Duke Kentucky properly files with the Commission.

Having considered the record and being otherwise sufficiently advised, the Commission finds that Duke Kentucky's request to amend its Rider PSM is granted, in part, and denied, in part. As Duke Kentucky's participation as an RPM member fundamentally changes how Duke Kentucky purchases and sells capacity, the Rider PSM must reflect the new construct to ensure that ratepayers and Duke Kentucky are appropriately compensated. Therefore, the Commission finds that it is reasonable, for a proper purpose, and in the public interest for Duke Kentucky to pass through certain BLIs related to its participation in the BRA/IA markets. Specifically, the following line items proposed by Duke Kentucky are approved for inclusion in the Rider PSM: 1610; 1650; 2605; 2620; 2625; 2630; 2640; 2650; 2660.[114] As to line Items 1600 and 2600[115], the Commission additionally approves the updated tariff language that specifically lists these BLIs in the Rider PSM, as these line items were approved in Case No. 2017-00321.[116]

The Commission cautions Duke Kentucky that, in the future, a general reference to a case does not substitute for specific and unambiguous language as to what BLIs are being recovered. Duke Kentucky should also make sure that its tariffs comply with the Commission's instructions regarding specific tariff language and that failure to include such language in the future could bar recovery for costs.

As to the other BLIs, the Commission shares the Attorney General's concerns regarding performance and compliance penalty BLIs, specifically BLIs 1660, 1661, 1662, 1663, 1664, 1665, and 1666 that Duke Kentucky proposed to recover through the Rider PSM. Duke Kentucky has the responsibility to avoid penalties resulting from its own behavior, and ratepayers should not automatically bear the burden of performance related penalties. The Commission also finds that BLIs 2660, 2661, 2662, 2663, 2664, 2665 and 2666 should not be included in the Rider PSM, as the Commission believes it is

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[114] Definitions for these items are found in Appendix A.

[115] Definitions for these items are found in Appendix A.

[116] The Commission required Duke Kentucky to list each of the PJM billing line items that will flow through Rider PSM in its compliance tariff in Case No. 2017-00321, but Duke Kentucky failed to do so for 1600 and 2600. Case No. 2017-00321, April 13, 2018 Order at 52.

appropriate to match the BLI revenues and expenses. At this time, Duke Kentucky has not met its burden of proof that including these BLIs in the Rider PSM is reasonable as a more thorough examination of these BLIs is necessary to determine why Duke Kentucky is receiving these penalties. If the issue arises in the future, Duke Kentucky should provide the Commission with evidence of how these line items are recorded in practice, including how often Duke Kentucky is facing penalties with an explanation for each infraction.

Because the Commission is not approving the inclusion of the performance related BLIs into the Rider PSM, the Commission will not specifically address each of the Attorney General's concerns and proposed guardrails explicitly. However, the Commission does find Mr. Kollen's testimony reasonable in so far as the Commission agrees that with the transition to the RPM construct, the amount of recovery through the Rider PSM could change substantially.[117] The Commission is concerned about the associated risks and incentives because through the Rider PSM Duke Kentucky would have increased opportunity to recover unreasonable or unjust rates without review and approval by the Commission. The Commission's underlying concern regarding the potential for unreasonable market exposure is in part why the Commission believes that the most prudent course of action in this case is to limit how expansive the Rider PSM can become and to delay further consideration of the issue until after Duke Kentucky has participated in the RPM construct for several quarters.

The Commission also finds that Duke Kentucky's request to shift the authorized sharing of capacity revenue and costs from 90 percent customers and 10 percent Duke

[117] Kollen Direct Testimony at 7-8.

Kentucky to 100 percent allocated to customers is denied. Duke Kentucky has not provided sufficient evidence that the shift for capacity-related allocation should be made, especially in light of the fact that the Rider PSM impact by the change to RPM and participation in the BRA is unknown. The Commission believes that the issue of allocation can be addressed in the next general adjustment of base rates, should Duke Kentucky wish to change the allocation. The Commission does not find Duke Kentucky's argument that "recovery of 90 percent of the cost to serve the customers' capacity need would mean that [Duke Kentucky] is being denied the ability to recover its costs of serving customers" to be compelling, as Duke Kentucky is still able to request cost-recovery in its next base rate case. Furthermore, a 100 percent allocation for customers means that Duke Kentucky may not have the incentive to manage risks associated with participation in the BRA or build its own generating resources to meet customer's demand. The Commission recognizes that an investor-owned utility must have some incentive to keep customer rates low and plan for future demand appropriately.

In addition, the Rider PSM rates should continue to be calculated using kWh. The Commission does not yet know the impact of shifting from an FRR to an RPM entity will have on the quarterly calculation.

Duke Kentucky is currently before the Commission in this matter and Case No. 2024-00354[118], both of which are asking for different amendments to the Rider PSM. The Commission notes that these separate filings create unnecessary confusion and could lead to conflicting results. If the Commission approved all of Duke Kentucky's requests

[118] Case No. 2024-00354, *Electronic Application of Duke Kentucky for 1) An Adjustment of Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (filed Dec. 2, 2024).

in Case No. 2024-00354, the Order could override all BLIs requested in this case related to the transition to being an RPM member. Instead, the Commission believes the more appropriate process would be to review the Rider PSM holistically and encourages Duke Kentucky to ensure that in future applications it does so.

IT IS THEREFORE ORDERED that:

1. Duke Kentucky's request to exit the FRR construct and transition to full participation in the RPM construct is approved.

2. Duke Kentucky's request to amend its Rider PSM is granted, in part, and denied, in part, as described in this Order.

3. Within 30 days after the transition from an FRR entity to an RPM entity, Duke Kentucky shall file the agreement with PJM.

4. Duke Kentucky shall file quarterly reports as set for in this Order beginning 30 days after the first quarter of participation in PJM as a RPM entity to include each BLI line item, if a penalty an explanation of the infraction and for each BLI line item, the amount.

5. Duke Kentucky shall file the BLI statements from PJM on a monthly basis for the first year it participates in the RPM construct.

6. Documents filed pursuant to ordering paragraphs 3–5 herein shall reference this case number and shall be retained in the post-case correspondence file.

7. The Amendments to the Rider PSM Tariff approved by the Commission in this Order shall only be effective coincident with the first day in which Duke Kentucky operates under the RPM construct.

8. Duke Kentucky's request to include BLIs 1610; 1650; 2605; 2620; 2625; 2630; 2640; and 2650; in the Rider PSM is approved.

9. Duke Kentucky's request to include BLIs 1660, 1661, 1662, 1663, 1664, 1665 and1666 and 2660, 2661, 2662, 2663, 2664, 2665, and 2666 in the Rider PSM is denied.

10. Duke Kentucky's request to reconcile the net capacity-related revenues and charges with customers receiving 100 percent of the benefit or costs of capacity outside of the current sharing percentages for other components of Rider PSM is denied.

11. This case is now closed and removed from the Commission's docket.

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PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Mary Pat Regan

Commissioner

ATTEST:

Linda Bridwell RP

Executive Director

ENTERED

MAY 16 2025 AH

KENTUCKY PUBLIC SERVICE COMMISSION

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2024-00285 DATED MAY 16 2025

NINETEEN PAGES TO FOLLOW

CUSTOMER GUIDE TO PJM BILLING

- Billing Line Items include PJM Open Access Transmission Tariff (OATT) references, PJM Operating Agreement (OpAgr) references, and PJM Manual references.
- Reports are available for viewing, printing, and downloading from PJM's Market Settlement Reporting System (MSRS).

BLI ID	Billing Line Item	Description	Reports
1100 **2100**	**Network Integration Transmission Service** (OATT Section 34, Attachments H-1 through H-17, Attachment H-A, and TOA Section 7.8 Manual 27, Section 5)	Network customers pay daily demand charges to PJM transmission owners using the applicable zonal or non-zone Network Integration Transmission Service rates. For transmission owners (except those in ATSI, PPL, ComEd, Dayton, Duke, and Duquesne zones), the charges for their own transmission facilities are not actually paid (i.e., exempted with an equal amount credits) and are shown only to identify their cost responsibility as ordered by FERC. ***Charges:*** Daily demand charges calculated as network customers' daily network service peak load contribution times 1/365th of the applicable zonal rate(s) for the zone(s) in which the network load is located. Non-zone network service peak load contributions are coincident with the PJM Region peak. Virginia Network Load customers in the Dominion Zone pay applicable rates for Underground Billing under FERC Opinion No. 555. ***Credits:*** PJM zonal network transmission service revenues allocated to the applicable zone's transmission owners on a transmission revenue requirement basis. PJM non-zone network revenues allocated to transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	***NITS Charge Summary*** ***NITS Credit Summary*** ***NITS Offset Charge Summary*** ***Non-Zone NITS Credit Summary*** ***Underground Transmission Service Charge Summary*** ***Underground Transmission Service Credit Summary***
1103 **2103**	**Underground Transmission Service** FERC Opinion No. 555	Virginia Network Load customers in the Dominion Zone pay applicable Network Integration Transmission Service rates for Underground Billing under FERC Opinion No. 555. ***Charges:*** Virginia Network Load customers in the Dominion Zone pay applicable Network Integration Transmission Service rates for Underground Billing under FERC Opinion No. 555. The Underground Transmission Service Charge is equal to the Underground Transmission Service Rate times the customers proportion of the Daily Peak Load. ***Credits:*** Transmission Owners in the Dominion Zone receive applicable Network Integration Transmission Service rates for Underground Billing under FERC Opinion No. 555. The Underground Transmission Service Credit is equal to the Total Zone Underground Transmission Service Charge times the Owner's Zone Revenue Requirement Share.	***Underground Transmission Service Charge Summary*** ***Underground Transmission Service Credit Summary***
1108 **1115** **2108**	**Transmission Enhancement** (OATT Schedule 12)	All network customers and merchant transmission owners pay transmission owners for required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates. ***Charges:*** All network customers serving load in a responsible zone pay for that zone's applicable projects' revenue requirements in proportion to their network service peak load share in that zone, and responsible merchant transmission owners also pay their share of applicable revenue requirements. Note that several EDCs bear these charges for the default suppliers in their territory. ***Credits:*** Total revenues allocated to the applicable transmission enhancement project owners, or the applicable transmission zone network customers for zonal TOs that include these project costs in their network rates. ***Settlement Charges (1115):***	***Transmission Enhancement Charge Summary*** ***Transmission Enhancement Credit Summary*** ***Transmission Enhancement Charge Adjustments (EL05-121-009) Summary***

BLI ID	Billing Line Item	Description	Reports
1109 **2109**	**MTEP Project Cost Recovery** Manual 29, Section 2.2.2, 2.3.2	Transmission projects built by MISO or PJM Transmissions Owners with cost responsibility in the other RTO/ISO. ***Charges:*** Charges are allocated to the respective MISO/PJM zone with cost responsibility for the projects. ***Credits:*** Charges collected from the responsible zone are paid to the responsible Transmission Owner as credits.	
1110 **2110**	**Direct Assignment Facilities** Manual 29, Section 2.2.2, 2.3.2	***Charges:*** The monthly charge to a Network Customer for necessary transmission facilities to ensure firm or non-firm point-to-point transmission service can be provided. ***Credits***: The month credit to a Transmission Owner for the necessary transmission facilities to ensure firm or non-firm point-to-point transmission service may be provided.	
1120 **2120**	**Other Supporting Facilities** Manual 29, Section 2.2.2, 2.3.2 OATT Attachment H	***Charges:*** The monthly charge to a Network Customer for low voltage facilities as specified in their service agreement and/or the applicable TO's Attachment H to the PJM tariff ***Credits:*** The monthly credit to a Transmission Owner for low voltage facilities as specified in their service agreement and/or the TO's Attachment H to the PJM tariff.	
1130 **2130**	**Firm Point-to-Point Transmission Service** (OATT Section 13.7, Schedule 7, and TOA Section 7.8 Manual 27, Section 6)	Firm point-to-point transmission customers pay demand charges for reserved capacity at the applicable tariff rates based on the term of the reservations. There is no charge for reserved capacity with a MISO point of delivery. ***Charges:*** Monthly demand charges for daily, weekly, monthly, and yearly delivery calculated based on the transmission customer's reserved capacity times the applicable tariff rate. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the weekly delivery rate times the highest amount of reserved capacity in any day during such week. ***Credits:*** Total firm transmission service revenues allocated to PJM transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	***Firm PTP Charges*** ***Firm PTP Credit Summary***
1133 **2133**	**Firm Point-to-Point Transmission Service Resale** OATT Section 23.1, Attachment A-1	A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee. ***Charges:*** The Firm PTP Transmission Service Resale Charge is equal to the Hourly Firm PTP Resale Rate times the Reseller's hourly Billable Profile Capacity ***Credits:*** The Firm PTP Transmission Service Resale Credit is equal to the Hourly Firm PTP Resale Rate times the Assignee's hourly Billable Profile Capacity	***Firm PTP Resale Charges*** ***Firm PTP Resale Credits***
1140 **2140**	**Non-Firm Point-to-Point Transmission Service** (OATT Sections 14.5 & 27A, Schedule 8 Manual 27, Section 6)	Non-firm point-to-point transmission customers pay demand charges for reserved capacity at the discounted rate. There is no charge for reserved capacity with a MISO point of delivery. ***Charges:*** Monthly demand charges for hourly, daily, weekly, and monthly delivery calculated based on the transmission customer's reserved capacity (in MWh) times the discounted rate of $0.67/MWh. Rebates are provided for transaction MWh curtailed by PJM and for transmission congestion charges. ***Credits:*** Total non-firm transmission service revenues allocated to PJM network and firm point-to-point transmission customers in proportion to their monthly demand charges.	***Non-Firm PTP Charges*** ***Non-Firm PTP Credit Summary***

BLI ID	Billing Line Item	Description	Reports
1200 **1205** **1400**	**Spot Market Energy** (OpAgr Schedules 1-3.2.1 & 3.3.1 and OATT Schedule 4 Manual 28, Section 3)	Day-ahead Spot Market energy position MWs are calculated in hourly intervals for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Real-time Spot Market energy position MWs are calculated in five minute increments for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. . In situations where five minute energy position interval data has not been provided, the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions. ***<u>Day-ahead Charges</u>:*** Net Day-ahead Spot Market energy positions are charged at the PJM-wide day-ahead system energy price for each hour. Charges are positive for energy purchased from the PJM Spot Market (i.e. energy withdrawals) and negative for energy delivered to the PJM Spot Market (i.e. energy injections) and totals are summed for each hour. ***<u>Balancing Charges</u>:*** Net real-time deviations from day-ahead energy positions are charged at one-twelfth the PJM-wide real-time system energy price for each five minute interval. In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. ***<u>Reconciliation Charges</u>:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the hourly PJM-wide real-time system energy price on a two-month billing lag.	***DA Daily Energy Transactions*** ***RT Daily Energy Transactions*** for customer review and verification ***Spot Market Energy Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary*** ***Energy Market and Congestion Loss Charge Details*** ***Balancing Generator LMP Charges***
1210 **1215** **1410** **2211** **2215** **2415**	**Transmission Congestion** (OpAgr Schedules 1-3.2.4, 3.4.1, & 5.1-5.2 Manual 28, Section 8)	The increased energy costs due to redispatch during the applicable interval when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs. Day-Ahead revenues collected are allocated as credits to FTR holders. Balancing Revenues are allocated as credits based on real-time load plus exports ratio shares. ***<u>Day-ahead Charges</u>:*** Day-ahead Implicit Congestion charges are calculated hourly as the sum of day-ahead withdrawal values (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at the applicable locations' day-ahead congestion prices) minus the sum of day-ahead injection values (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at the applicable locations' day-ahead congestion prices). Explicit Congestion charges for day-ahead energy transactions are calculated hourly and equal the scheduled MWh times the difference between day-ahead sink and source congestion prices. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***<u>Balancing Charges</u>:*** Balancing Implicit Congestion charges are calculated for each five minute interval as the sum of balancing withdrawal congestion values (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead versus real-time load without losses, and sale transactions, priced at one-twelfth of the applicable locations' real-time congestion prices) minus the sum of balancing injection congestion values (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead versus real-time generation and purchase transactions, priced at one-twelfth of the applicable locations' real-time congestion prices). In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. Explicit Congestion charges for balancing energy transactions are calculated for each five minute interval and equal any real-time deviations from the transaction MWs cleared day-ahead times one-twelfth of the difference between the real-time sink and source congestion prices. In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive	***Transmission Congestion Charge Summary*** ***Explicit Congestion Charges*** ***Energy Market and Congestion Loss Charge Details*** ***FTR Target Credits*** ***Hourly Transmission Congestion Credits*** ***Congestion and Loss Load Recon Charges*** ***Congestion Uplift Charge Summary*** ***Network ARR Target Credit Summary*** ***Cross-Monthly Congestion Credit Summary*** ***Balancing Transmission Congestion Credit Summary*** ***Balancing Transmission Congestion Load Reconciliation Credit Summary***

BLI ID	Billing Line Item	Description	Reports
		or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Day-ahead Credits:*** Total day-ahead congestion revenues (including net day-ahead MISO and NYISO Market-to-Market adjustments) are allocated as hourly credits based on FTR target allocations (FTR MW times the difference between day-ahead FTR sink and source congestion prices). The monthly total of excess hourly congestion credits and FTR Auction net revenues remaining after distribution to ARRs are used to proportionately reduce any remaining FTR target deficiencies in all hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period. ***Balancing Credits:*** Total Balancing Transmission Congestion Charges (including MISO and NYISO real-time Market-to-Market adjustments and inadvertent interchange congestion contribution) are allocated among the PJM market participants in proportion to their real-time load (de-rated for transmission losses) plus their real-time PJM exports as a percentage of the total PJM load (excluding losses) and exports. ***Reconciliation Charges and Credits:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	
1216	**Pseudo-Tie Balancing Congestion Refund** OATT Schedule 16	Generation resources that implement interchange via a Pseudo Tie between the Native Balancing Authority and Attaining Balancing Authority are able to offer into both the Attaining and Native Balancing Authority's energy market. Pseudo Tie Generator Imports into PJM are modeled as regular units in the PJM Energy Market, and as such follow the same bidding rules as units which are electrically inside PJM and participating in the PJM Energy Market. Pseudo Tie Generator Exports out of PJM are charged the Explicit Congestion and Loss LMP difference between their source generator and sink external PJM interface point. The real-time MW value used is the value as reported to PJM via Power Meter. ***Charges:*** The Pseudo-Tie Balancing Congestion Refund Charge is calculated in 5-Minute intervals. The Pseudo-Tie Balancing Congestion Refund Charge is equal to the Pseudo-Tie Transaction Deviation MW times the Pseudo-Tie Real-Time Congestion Overlap Refund Price.	***Pseudo-Tie Balancing Congestion Refund Charge Summary***
2217	**Planning Period Excess Congestion** (OpAgr Schedule 5.2.6 Manual 28, Section 8.4.4)	For planning years in which the sum of total PJM congestion revenues collected during the planning year was greater than the sum of FTR holders' total net FTR Targets, Planning Period Excess Congestion credits are awarded to the ARR holders at the end of the planning year (May) to distribute those remaining excess congestion revenues. Planning Period Excess Congestion credits can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. Planning Period Excess Congestion credits are allocated to ARR holders in proportion to their net positive total ARR Target Credits for the planning year.	***Cross-Monthly Congestion Credit Summary***

BLI ID	Billing Line Item	Description	Reports
1218 **2218**	**Planning Period Congestion Uplift** (OpAgr Schedules 5.2.5 & 5.2.6 Manual 28, Section 8)	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. The "Planning Period Congestion Uplift credit" is a "make-whole" congestion credit to FTR holders to satisfy any previously unfulfilled FTR Target Credits that remain at the end of the planning year. A summary of FTR Targets and all applicable Congestion Credits broken down by month can be viewed in the "Cross-Monthly Congestion Credit Summary" report in MSRS. Select the "All Billed" option for the period from 6/1/12 through 5/31/13 to see the complete set of details. The "Planning Period Congestion Uplift charge" is the participant's share of the allocated costs of providing the Uplift credits. Charges are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year. Details of this charge allocation can be viewed in the "Congestion Uplift Charge Summary" report in MSRS. The calculation for the Uplift charge is: (positive FTR Target credit / Total PJM Positive FTR Target Credit) * PJM Total FTR and ARR Uplift Credit. The uplift process is also outlined in Manual 28, sections 8.1 and 8.4.4	***Congestion Uplift Charge Summary*** ***Cross-Monthly Congestion Credit Summary***

BLI ID	Billing Line Item	Description	Reports
1220 1225 1420 2220 2420	**Transmission Losses** (OpAgr Schedules 1-3.2.5, 3.4.2, & 5.4-5.5 Manual 28, Section 9)	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). ***Day-ahead Charges:*** Day-ahead Transmission Loss charges are calculated hourly as the sum of day-ahead withdrawal loss values (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at the applicable locations' day-ahead loss prices) minus day-ahead injection loss values (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at the applicable locations' day-ahead loss prices). Explicit loss charges for day-ahead energy transactions are calculated hourly and equal the scheduled MWh times the difference between day-ahead sink and source loss prices. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Balancing Charges:*** Balancing Loss charges are calculated for each five minute interval as balancing withdrawal loss values (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead versus real-time load, without losses, and sale transactions priced at one-twelfth of the applicable locations' real-time loss prices) minus balancing injection loss values (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead versus real-time generation and purchase transactions priced at one-twelfth of the applicable locations' real-time loss prices). In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour.. Explicit loss charges for balancing energy transactions are calculated for each five minute interval and equal any real-time deviations from day-ahead transaction MW times one-twelfth of the difference between real-time sink and source loss prices. In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Credits:*** Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange and spot market energy imbalance) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving a reduced percentage of their allocation). ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag. ***Reconciliation Credits:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving a reduced percentage of their allocation) on a two-month billing lag.	***Transmission Loss Charge Summary*** ***Explicit Loss Charges*** ***Energy Market and Congestion Loss Charge Details*** ***Transmission Loss Credit Summary*** ***Congestion and Loss Load Recon Charges*** ***Transmission Loss Load Recon Credit Summary***

BLI ID	Billing Line Item	Description	Reports
1230 **1430**	**Inadvertent Interchange** (OpAgr Schedule 1-3.7 Manual 28, Section 18)	***Charges:*** PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	***Inadvertent Interchange Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary***
1242 **1243** **1246** **2240** **2241** **2246**	**Load Response** (OpAgr, just prior to Schedule 2 Manual 28, Section 11)	***Credits:*** Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWs times LMP. In situations where five-minute interval data has not been provided, the Load Response energy value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions. Those MW positions are then multiplied by one-twelfth of the applicable interval real-time zonal or aggregate LMP to determine credits, which are then summed for the hour. ***Charges:*** For day-ahead and real-time economic load response, the charges are allocated to all real-time load where load is served in a zone that has benefitted from load reductions plus real-time exports. For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	***Load Response Summary*** ***Real-time Load Response Credits*** ***Econ Load Response Zonal Charge Allocations*** ***Emergency Load Response Allocation Summary*** ***Emergency Load Response Allocation Credits***
1245 **2245**	**Pre-Emergency and Emergency Load Response** (OpAgr, just prior to Schedule 2 Manual 28, Section 11 Manual 29, Section 2.2.1)	***Credits:*** Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWs times LMP. In situations where five-minute interval data has not been provided, the Load Response energy value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions. Those MW positions are then multiplied by one-twelfth of the applicable interval real-time zonal or aggregate LMP to determine credits, which are then summed for the hour. The Emergency Load Response Charge is the sum of the Total PJM Emergency Load Response Energy Credits, the product of the Total PJM Emergency Load Response Make-Whole Credits and the maximum of the Positive Bal Net Interchange Used MWh and zero, divided by the Total PJM Bal Positive Interchange Used. ***Charges:*** For day-ahead and real-time economic load response, the charges are allocated to all real-time load where load is served in a zone that has benefitted from load reductions plus real-time exports. For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases. The Emergency Load Response charge is the sum of the PJM Member’s charges for PJM Emergency Load Response. The Emergency Load Response Make-Whole Credit is equal to if the sum of the Emergency Load Response Make-Whole Credit across all hours of the day > 0, [(the product ofn the Emergency Load Response Bid Price and the RT Load Response Actual MWh Relief plus the Shutdown Cost all minus the Emergency Load Response Energy Credit	***Emergency Load Response Allocation Summary*** ***Emergency Load Response Allocation Credits***

BLI ID	Billing Line Item	Description	Reports
1250	**Meter Error Correction** (OpAgr Schedule 1-3.6 Manual 28, Section 12)	***Charges:*** Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	***Meter Correction Charge Summary*** ***Meter Correction Allocation Charge Summary***
1260 **2260**	**Emergency Energy** (OpAgr Schedules 1-3.2.6, 3.3.4, 3.5.1, & 4.3 Manual 28, Section 10)	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. ***Charges:*** For each applicable five-minute interval, net costs of emergency energy purchased by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position, except for purchases for external control areas' MinGen Emergencies where costs are allocated to deviations that create a longer position. ***Credits:*** For each applicable five-minute interval, net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	***Emergency Energy Charge and Credit Allocation Summary*** ***Emergency Energy Transactions***
1301 **1302** **1303** **1305** **1440**	**PJM Scheduling, System Control & Dispatch Service** (OATT Schedules 1 and 9-1 through 9-4 Manual 27, Section 2)	***Charges:*** PJM's monthly operating expenses for the following service categories are allocated to PJM members on an unbundled basis. Control Area Administration – Monthly formula rate is charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use (in MWh) includes network customers' real-time load and point-to-point customers' real-time energy use. Financial Transmission Rights Administration – Component 1: Monthly formula rate is charged to FTR holders based on FTR MW and hours each FTR is in effect (regardless of congested hours and dollar value of FTR). Component 2: Monthly formula rate is charged to FTR Auction participants based on the number of hours associated with each FTR obligation bid submitted in an FTR Auction (this rate is multiplied by 5 for FTR options). Market Support – Component 1: Monthly formula rate is charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. Component 2: Monthly formula rate is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Capacity Resource and Obligation Management – Monthly formula rate is charged to LSEs based on their daily unforced capacity obligations and to capacity resource owners based on their daily unforced capacity (including FRRs). ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the Control Area Administration Service Rate plus the Market Support Service Rate for transmission customers on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
1313	**PJM Settlement, Inc.** (OATT Schedule 9-PJMSettlement Manual 27, Section 2)	***Charges:*** Monthly formula rate is charged to each customer account receiving an invoice from PJM Settlement on per-invoice basis.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details***

BLI ID	Billing Line Item	Description	Reports
1314 1444	**MMU Funding** (OATT Schedule 9-MMU Manual 27, Section 2)	***Charges:*** Component 1: The rate is charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. Component 2: Annual rate is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the MMU rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
1315 1445	**FERC Annual Recovery** (OATT Schedule 9-FERC Manual 27, Section 2)	***Charges:*** The rate is charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the FERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
1316 1446	**Organization of PJM States, Inc. (OPSI) Funding** (OATT Schedule 9-OPSI Manual 27, Section 2)	***Charges:*** The rate is charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the OPSI rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
1317 1447	**North American Electric Reliability Corp. (NERC)** (OATT Schedule 10-NERC Manual 27, Section 2)	***Charges:*** The rate is charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of NERC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the NERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
1318 1448	**Reliability First Corp. (RFC)** (OATT Schedule 10-RFC Manual 27, Section 2)	***Charges:*** The rate is charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of RFC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the RFC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
1319 1449	**Consumer Advocates of PJM States, Inc. (CAPS) Funding** (OATT Schedule 9-CAPS Manual 27, Section 2)	***Charges:*** The rate is charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load (including losses) and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the CAPS rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Summary*** ***Schedule 9 & 10 Daily Usage Details*** ***Schedule 9 & 10 Load Recon Charge Summary***

BLI ID	Billing Line Item	Description	Reports
1320 **1450** **2320**	**Transmission Owner Scheduling, System Control and Dispatch Service** (OATT Schedule 1A Manual 27, Section 2)	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. ***Charges:*** Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of $0.0912/MWh based on their energy deliveries including losses and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve. ***Credits:*** The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal $/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	***Sched 1A Charge Summary*** ***Sched 1A Credit Summary*** ***Sched 1A Load Recon Charge Summary***
1330 **2330**	**Reactive Supply and Voltage Control from Generation and Other Sources Service** (OATT Schedule 2 Manual 27, Section 3)	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. ***Credits:*** Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements. ***Charges:*** Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	***Reactive Charge Summary***

BLI ID	Billing Line Item	Description	Reports
1340 **1460** **2340**	**Regulation and Frequency Response Service** (OpAgr Schedules 1-3.2.2, 3.2.2A, 3.3.2, & 3.3.2A and OATT Schedule 3 Manual 28, Section 4)	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. ***Credits:*** Generators and demand resources receive five minute interval credits for pool- and self-scheduled regulation (with consideration of the resource's performance) priced at one-twelfth of the regulation market capability clearing price. Generators and demand resources receive five minute interval credits for pool- and self-scheduled regulation (with consideration of the resource's performance and the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio)) priced at one-twelfth of the regulation market performance clearing prices. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost. ***Charges:*** PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). Hourly charges are allocated based on obligation ratio shares times the sum of total PJM Regulation credits awarded for each hour of the Operating Day In addition, any lost opportunity or other unrecovered cost payments that PJM provides to regulation suppliers are allocated to regulation market purchasers based on the amount of Regulation they purchased from the market in that hour. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	***Regulation Summary*** ***Regulation Credits*** ***Load Response Regulation Credits*** ***Reg Load Recon Charge Summary***
1360 **1470** **2360** **2366**	**Synchronized Reserve** (OpAgr Schedules 1-3.2.3A & 3.3.5 and OATT Schedule 5 Manual 28, Section 6)	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and economic load response that can be converted fully into energy within ten minutes. ***Day-ahead Credits:*** Day-ahead Synchronized Reserve Market credits are paid hourly to pool-scheduled or self-scheduled resources that are assigned synchronized reserve MWs within the day-ahead market by multiplying the hourly day-ahead synchronized reserve MWs assigned by the day-ahead synchronized reserve market clearing price. ***Balancing Credits:*** Balancing Synchronized Reserve Market credits for pool and self-scheduled resources are calculated for each five minute interval and equal the difference between the capped real-time synchronized reserve assignment and the day-ahead synchronized reserve assignment multiplied by one-twelfth of the applicable reserve zone's real-time synchronized reserve market clearing price (SRMCP). Resources failing to provide the capped real-time synchronized reserve assignment during a synchronized reserve event are assessed a shortfall charge equal to the product of the applicable real-time SRMCP and the lesser of the amount of the MW shortfall during the event or the capped real-time synchronized reserve assignment MW for all five-minute intervals the resource was assigned or self-scheduled for real-time synchronized reserve during the Operating Day. Additional lost opportunity cost credits are provided to pool-scheduled synchronized reserve resources for any portion of the total day-ahead and real-time synchronized reserve offer plus opportunity cost, energy use cost, and start-up cost not recovered via the total day-ahead and balancing Synchronized Reserve Market Clearing Price revenues less any shortfall charges. If applicable, additional profits from other reserve markets and/or the energy market (Market Revenue Neutrality Offset) or the cost attributable to a reserve market buy back (Opportunity Cost Credit Owed) for the same five-minute interval are also included as additional offsets in the lost opportunity cost credit determination. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their applicable reserve zone or active sub-zone total assignments (adjusted for any bilateral synchronized reserve transactions). For each hour of the Operating Day, Synchronized Reserve Market Clearing Price charges are calculated for each applicable reserve zone or active sub-zone based on the adjusted obligation ratio shares times the sum of total PJM day-ahead and balancing Synchronized Reserve market clearing price credits adjusted for shortfall charges. In addition, Synchronized Reserve lost opportunity cost charges are calculated each hour for each applicable reserve zone or active sub-zone	***Day-ahead Synchronized Reserve Credits*** ***Balancing Synchronized Reserve Credits*** ***Market Revenue Neutrality Increased Revenue Details*** ***Market Revenue Neutrality Offset Details*** ***Reserve Market Summary*** ***Synchronized Reserve Charges*** ***Synchronized Reserve Retroactive Penalty Charges*** ***Synchronized Reserve Load Recon Charge Summary***

BLI ID	Billing Line Item	Description	Reports
		by allocating the total PJM synchronized reserve lost opportunity cost credits for the hour to market participants that do not meet their hourly obligation, in proportion to their synchronized reserve purchases for the hour. Resources that fail to provide assigned synchronized reserve during a synchronized reserve event also incur a retroactive penalty charge. This charge is determined by multiplying the retroactive penalty MWs times the RT SRMCP for all real-time settlement intervals the resource was assigned for self-scheduled to provide synchronized reserve for a duration immediately preceding the synchronized reserve event. ***<u>Reconciliation Charges</u>:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable location's (reserve zone or active sub-zone and non-zone) $/MWh billing determinant calculated as the total applicable location's Synchronized Reserve charges divided by the total MWh of PJM real-time load served in that location on a two-month billing lag.	
1361 **1471** **2361** **2367**	**Secondary Reserve** **(**OpAgr Schedules 1-3.2.3A.001 Manual 28, Section 19)	PJM conducts secondary reserve markets to ensure the capability of off-line and on-line generation and economic load response available to provide energy with a response between ten minutes and thirty minutes as necessary to meet the 30-minute reserve requirement. ***<u>Day-ahead Credits</u>:*** Day-ahead Secondary Reserve Market credits are paid hourly to resources that are assigned secondary reserve MWs within the day-ahead market by multiplying the hourly day-ahead secondary reserve MWs assigned by the day-ahead secondary reserve market clearing price. ***<u>Balancing Credits</u>:*** Balancing Secondary Reserve Market credits for pool and self-scheduled resources are calculated for each five minute interval and equal the difference between the capped real-time secondary reserve assignment (including any reductions for shortfall MWs) and the day-ahead secondary reserve assignment multiplied by one-twelfth of the applicable reserve zone' real-time secondary reserve clearing price (SecRMCP). Additional lost opportunity cost credits are provided to pool-scheduled secondary reserve resources for each five minute interval for any portion of secondary reserve opportunity costs not recovered via the total day-ahead and balancing secondary reserve market clearing price revenues. If applicable, additional profits from other reserve markets and/or the energy market (Market Revenue Neutrality Offset) or the cost attributable to a reserve market buy back (Opportunity Cost Credit Owed) for the same five-minute interval are also included as additional offsets to the lost opportunity cost credit determination. ***<u>Charges</u>:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly secondary reserve obligation equal to their real-time load (without losses) ratio share of their applicable reserve market's zone or active sub-zone total real-time secondary reserve supplied (adjusted for any bilateral secondary reserve transactions). For each hour of the Operating Day, Secondary Reserve Market Clearing Price charges are calculated for each applicable reserve market zone and active sub-zone based on the obligation ratio share times the sum of total day-ahead and balancing PJM Secondary Reserve market clearing price credits. In addition, Secondary Reserve lost opportunity cost charges are calculated for each hour and for each applicable reserve market zone or active sub-zone by allocating the total PJM Secondary Reserve lost opportunity credits to market participants in proportion to their Secondary Reserve obligation ratio share for the hour. ***<u>Reconciliation Charges</u>:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable location's (reserve zone or active sub-zone and non sub-zone) $/MWh billing determinant calculated as the total applicable location Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in that location on a two-month billing lag.	***Day-ahead Secondary Reserve Credits*** ***Balancing Secondary Reserve Credits*** ***Secondary Reserve Charges*** ***Reserve Market Summary*** ***Market Revenue Neutrality Increased Revenue Details*** ***Market Revenue Neutrality Offset Details*** ***Secondary Reserve Load Recon Charge Summary***

BLI ID	Billing Line Item	Description	Reports
1362 1472 2362 2368	**Non-Synchronized Reserve** (OpAgr Schedules 1-3.2.3A.001 & 3.3.5A Manual 28, Section 7)	PJM conducts non-synchronized reserve markets to ensure the capability of generation off-line and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. ***Day-ahead Credits:*** Day-ahead Non-Synchronized Reserve Market credits are paid hourly to resources that are assigned non-synchronized reserve MWs within the day-ahead market by multiplying the hourly day-ahead non-synchronized reserve MWs assigned by the day-ahead non-synchronized reserve market clearing price. ***Balancing Credits:*** Balancing Non-Synchronized Reserve Market credits for pool and self-scheduled resources are calculated for each five minute interval and equal the difference between the real-time non-synchronized reserve assignment and the day-ahead non-synchronized reserve assignment multiplied by one-twelfth of the applicable non-synchronized reserve clearing price. Additional lost opportunity cost credits are provided to pool-scheduled non-synchronized reserve resources for each five minute interval for any portion of non-synchronized reserve opportunity costs not recovered via the total day-ahead and balancing non-synchronized reserve market clearing price revenues. If applicable, additional profits from other reserve markets and/or the energy market (Market Revenue Neutrality Offset) or the cost attributable to a reserve market buy back (Opportunity Cost Credit Owed) for the same five-minute interval are also included as additional offsets to the lost opportunity cost credit determination. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly non-synchronized reserve obligation equal to their real-time load (without losses) ratio share of their applicable reserve market's zone or active sub-zone total non-synchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). For each hour of the Operating Day, Non-Synchronized Reserve Market Clearing Price charges are calculated for each applicable reserve market zone and active sub-zone based on the obligation ratio share times the sum of total day-ahead and balancing PJM Non-Synchronized Reserve market clearing price credits. In addition, Non-Synchronized Reserve lost opportunity cost charges are calculated for each hour and for each applicable reserve market zone or active sub-zone by allocating the total PJM Non-Synchronized Reserve lost opportunity credits to market participants in proportion to their non-synchronized Reserve obligation ratio share for the hour. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable location's (reserve zone or active sub-zone and non sub-zone) \$/MWh billing determinant calculated as the total applicable location Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in that location on a two-month billing lag.	***Day-ahead Non-Synchronized Reserve Credits*** ***Balancing Non-Synchronized Reserve Credits*** ***Reserve Market Summary*** ***Market Revenue Neutrality Increased Revenue Details*** ***Non-Synchronized Reserve Charges*** ***Non-Synchronized Reserve Load Recon Charge Summary***
1365 1475 2365	**Day-ahead Scheduling Reserve** (OpAgr Schedules 1-3.2.3A.01 and OATT Schedule 6 Manual 28, Section 19)	Effective October 1, 2022, Day-ahead Scheduling Reserve was removed from the PJM market. Reconciliation Charges will conclude in the December 2022 monthly bill. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the \$/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	***Day-ahead Scheduling Reserve Load Recon Charge Summary***
1370 1375 1376 1478 2370 2375 2376	**Operating Reserve** (OpAgr Schedules 1-3.2.3 & 3.3.3 and OATT Schedule 6 Manual 28, Section 5 and Section 11)	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. ***Day-ahead Credits:*** Daily credits provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP. ***Balancing Credits:*** Daily credits for specified operating period segments are provided to eligible pool-scheduled generators, demand response, and import transactions in real-time, and will be evaluated on a five minute interval basis for any portion of their offer amount in excess of: (1) scheduled MWh times	***Operating Reserve Charge Summary*** ***Balancing Operating Reserve Generator Credit Details*** ***Operating Reserve Lost Opportunity Cost Credits*** ***Operating Reserve Transaction Credits*** ***Operating Reserve Generator Deviations*** ***Operating Reserve Generator Deviations – 5 min*** ***Operating Reserve Deviation Summary*** ***Operating Reserve Deviation summary – 5 min***

BLI ID	Billing Line Item	Description	Reports
		day-ahead bus LMP; (2) MW deviation from day-ahead schedule times one-twelfth of real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any secondary reserve market revenues in excess opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs; (7) any applicable reactive services credits; and (8) less any amounts attributed to the Market Revenue Neutrality Offset. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also evaluated on a five minute interval basis and are provided to generators reduced or suspended by PJM for reliability purposes. ***Day-ahead Charges:*** Total daily cost of operating reserve in the day-ahead market excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares. ***Balancing Charges:*** Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of five minute interval real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWs); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. In situations where five minute interval data has not been provided (including all day-ahead data), the hourly MW value provided will be scaled or flat-profiled across each of the applicable five minute intervals of the hour in order to allow for the calculation of MW deviations on a five minute interval basis. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an daily basis using a $/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	***Operating Reserve Transaction Credits*** ***Balancing Operating Reserves for Load Response Credit*** ***Operating Reserve for Load Response Deviation Charge Summary*** ***Operating Reserve for Load Response Charge Allocations*** ***Regional Balancing Operating Reserve Charge Summary*** ***Balancing Operating Reserve Load Recon Charge Summary*** ***CT Lost Opportunity Cost Forfeiture***
1371 **1376** **2371** **2376**	**Day-ahead and Balancing Operating Reserve for Load Response** Manual 28, Section 5.1	***Charges:*** The cost of Operating Reserve for Load Response for an Operating Day, is calculated as a ratio-share based on the real-time exports from PJM and real-time loads in each Zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month. ***Credits:*** Credits for reducing load are based on the actual MWh relief provided in excess of committed day-ahead load reductions plus an adjustment for losses if following dispatch by PJM. Payment is not made for any load reductions in real-time when the real-time five minute LMP is less than the price determined under the Net Benefits Test.	***Operating Reserve for Load Response Charge Allocation*** ***Operating Reserve for Load Response Deviation Charge Summary*** ***Day-Ahead Operating Reserve for Load Response Credit*** ***Balancing Operating Reserve for Load Response Credit***
1377 **1480** **2377**	**Synchronous Condensing** (OpAgr Schedule 1-3.2.3 Manual 28, Section 5)	***Credits:*** Daily credits for condensing and energy use costs are calculated on a five minute interval basis and are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services. ***Charges:*** Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	***Synchronous Condensing Credits*** ***Synchronous Condensing Charge Summary*** ***Synchronous Condensing Load Recon Charge Summary***
1378 **1490** **2378**	**Reactive Services** (OpAgr Schedule 1-3.2.3B Manual 28, Section 5)	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or to be compensated for their lost opportunity costs. ***Credits:*** Daily credits are calculated on a five minute interval basis for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services.	***Reactive Services Credits*** ***Synchronous Condensing Credits*** ***Reactive Services Charge Summary*** ***Reactive Svcs Load Recon Charge Summary***

BLI ID	Billing Line Item	Description	Reports
		Charges: Total daily cost of reactive services and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control is allocated separately for each PJM transmission zone based on real-time load (without losses) ratio shares in the applicable transmission zone. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's $/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	
1380 **2380**	**Black Start Service** (OATT Schedule 6A Manual 27, Section 7)	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. ***Credits:*** Monthly credits provided to generators with approved black start revenue requirements. ***Charges:*** Monthly pool-wide black start revenue requirements and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining black start revenue requirements nominated by each zonal Transmission Owner and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing not recovered from point-to-point customers are allocated to the network customers serving load in that transmission zone based on their monthly network service peak load contributions.	***Black Start Charge Summary***
1390 **2390**	**Fuel Cost Policy Penalty** (OpAgr Schedule 2, Section 5 Manual 15, Section 2)	Market Sellers are required to have a PJM-approved Fuel Cost Policy for energy market units submitting cost-based offers. A Fuel Cost Policy Penalty is assessed if PJM determines and the Market Monitoring Unit (MMU) agrees or the MMU determines and PJM agrees that a cost-based offer is not compliant with the PJM-approved Fuel Cost Policy or other applicable cost-based offer guidelines in Schedule 2 of Operating Agreement. ***Charges:*** An hourly charge is assessed to the participant that applies to all hours that the Market Seller does not have a PJM approved Fuel Cost Policy or a cost offer not in accordance with its Fuel Cost Policy. ***Credits:*** Fuel Cost Policy Penalties are allocated as credits based on real-time load ratio share in the hour for which the Fuel Cost Policy Penalty has been assessed.	***Fuel Cost Policy Penalty Charge Details*** ***Fuel Cost Policy Penalty Credit Allocation Summary***
1500 **2500**	**Financial Transmission Rights Auction** (OpAgr Schedule 1-7.3.8 Manual 28, Section 16)	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. ***Charges:*** Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price. ***Credits:*** Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	***FTR Auction Charges and Credits***
2510	**Auction Revenue Rights** (OpAgr Schedule 1-7.4 Manual 28, Section 17)	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. ***Credits:*** Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	***ARR Target Credits***
1600 **2600**	**RPM Auction** (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	***Credits:*** Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity. ***Charges:*** Each buy bid MW cleared in an incremental auction adjusted by cleared buy bid transactions	***RPM Auction Charges and Credits*** ***RPM Auction Make-Whole Charge Summary*** ***RPM Auction Charges***

BLI ID	Billing Line Item	Description	Reports
		pays the applicable LDA's resource clearing price. Resource make-whole payments for an incremental auction are also allocated as charges to Market Buyers based on the MW shares of cleared buy bids adjusted by cleared buy bid transactions for the incremental auction. Resource make-whole payments for the base residual auction and the portion of the resource make-whole payment for an incremental auction that would be based on PJM cleared buy bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal Capacity Price.	***RPM Auction Credits***
2605	**RPM Seasonal Capacity Performance Auction** Manual 18, Section 9.3.1	***<u>Credits</u>***: Each generation, demand, or energy efficiency resource provider that clears Seasonal Capacity Performance-Summer sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Summer sell offer segments times the resource clearing price applicable to the resource's Seasonal Capacity Performance-Summer sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for June through October and May of the Delivery Year.	***RPM Auction Credits***
1610	**Locational Reliability** (OATT Att. DD, Section 5.14 Manual 18, Section 9.2)	***<u>Charges</u>:*** Each LSE is charged for their daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.	***Locational Reliability Charge Summary***
2625	**LSE PRD** Manual 18, Section 9.4.4	***<u>Credits</u>***: A PRD Provider will receive a PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to a PRD Provider in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone on a given day. The PRD Credit PRD Performance penalties are assessed to the PRD Provider in the registration. When the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone.	***PRD Credits***
2630	**Capacity Transfer Rights** (OATT Att. DD, Section 5.15 Manual 18, Section 9.3)	To recognize the value of import capability to constrained LDAs, Capacity Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher load charges. ***<u>Credits</u>:*** CTRs equal to the unforced capacity imported into the LDA (less any incremental CTRs) are allocated to LSEs in that LDA based on daily unforced capacity obligations. These MW allocations are priced at the difference between the LDA's clearing price and the unconstrained price.	***CTR Credit Summary***
2640	**Incremental Capacity Transfer Rights** (OATT Att. DD, Section 5.16, OATT Schedule 12A (b) Manual 18, Section 9.3)	Incremental CTRs are provided to fund for transmission upgrades (not including qualifying transmission upgrades cleared in the Base Residual Auction) that increase import capability into a constrained LDA. Incremental CTRs for Incremental-Rights Eligible Required Transmission Enhancements are determined and allocated as defined in Schedule 12A of the Tariff. ***<u>Credits</u>:*** Incremental CTR MW are priced at the sum of: 1) locational price adder of the sink LDA minus that of the Source LDA from the Base Residual Auction; and 2) locational price adder of the sink LDA minus that of the source LDA from the Second Incremental Auction multiplied by the increase in unforced capacity imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the base unforced capacity imported into the sink LDA. Incremental CTR credits determined for an Incremental-Rights Eligible Required Transmission Enhancement are allocated to the responsible customers that are assigned cost responsibility for the transmission enhancements in accordance with the cost allocations in the appendix to Schedule 12. Responsible customers include Network customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners. Network customers serving load in a responsible zone receive credits in proportion to their network service peak load share in that zone.	***Incremental CTR Credits*** ***Incremental CTR for Required Transmission Enhancement Credits***
1650	**Auction**	Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets.	***Auction Specific MW Transaction Charges and Credits***

BLI ID	Billing Line Item	Description	Reports
2650	**Specific MW Transaction** (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	***Charges:*** Sellers are charged for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect. ***Credits:*** Buyers are credited for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect.	
1661 **2661**	**Capacity Resource Deficiency** (OATT Att. DD, Section 8 Manual 18, Section 9.1)	Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. ***Charges:*** Each capacity resource's deficiency MW for each day it is deficient pays the daily deficiency rate. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
1662 **2662**	**Generation Resource Rating Test Failure** (OATT Att. DD, Section 7 Manual 18, Section 9.1)	Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each capacity resource's installed capacity minus its highest rating in the relevant testing period (on an unforced capacity basis) pays a daily deficiency rate which is the weighted average capacity resource clearing price plus the higher of: 1) 0.2 times the weighted average capacity resource clearing price or 2) $20/MW-day; ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
1663 **2663**	**Qualifying Transmission Upgrade Compliance Penalty** (OATT Att. DD, Section 12 Manual 18, Section 9.1)	Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. ***Charges:*** Capacity market sellers with import capability cleared in a base residual auction based on a qualifying transmission upgrade are charged each day that the upgrade is not in service during the applicable delivery year and the seller does not obtain replacement capacity resources. The import capability MW are charged at the higher of the following rates: 1) two times the locational price adder of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable LDA. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
1666 **2666**	**Load Management Test Failure** (OATT Att. DD, Section 11A Manual 18, Section 9.1)	Sellers with committed Demand Resources that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the August monthly bill issued in September after the conclusion of the Delivery Year. ***Charges:*** Net capability testing shortfall MW are charged daily at the weighted annual revenue rate for the applicable zone plus the greater of 0.2 times that weighted annual revenue rate or $20/MW-day. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Load Management Test Failure Charge Summary*** ***Load Management Test Failure Credit Summary***
1667 **2667**	**Non-Performance Charges and Bonus Performance Credits** Manual 18, Section 8.4A	***Charges:*** Capacity Performance Resource commitments and PRD commitments are exposed to Non-Performance Charges for underperformance during Emergency Actions throughout the entire Delivery Year. A Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Interval. Resources that fail to perform to their expected performance are subject to Non-Performance Charge. ***Credits:*** Capacity Performance Resource commitments and PRD commitments are exposed to Non-Performance Charges for underperformance during Emergency Actions throughout the entire Delivery Year. A Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Interval.Resources that over-perform may be eligible for Bonus Performance Credit.	***NPA Billing Month Summary*** ***NPA DSR Reg Performance Details*** ***NPA DSR Resource Charge Details*** ***NPA Resource Charge Details*** ***NPA Resource Charge Dist Summ*** ***NPA Resource Outage Details*** ***NPA Unit Performance Details***

BLI ID	Billing Line Item	Description	Reports
1669 **2669**	**PRD Commitment Compliance Penalty** (RAA Schedule 6.1, Section I Manual 18, Section 9.4)	A PRD Provider with a positive daily commitment compliance shortfall in a sub-zone/zone for RPM or FRR will be assessed a Daily PRD Commitment Compliance Penalty. ***Charges:*** Commitment compliance shortfall MW are charged daily at the Delivery Year Forecast Pool Requirement times the PRD Commitment Compliance Penalty Rate. ***Credits:*** Total revenues each day are allocated to all entities that committed Capacity Resources in the RPM Auction for that delivery year based on their daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred.	***PRD Commitment Compliance Penalty Charges*** ***PRD Commitment Compliance Penalty Credits***
1900	**Unscheduled Transmission Service** (OpAgr Sch1-5.3a Manual 28, Section 14)	***Charges:*** Hourly charges to NYISO for any costs incurred due to unscheduled use of the PJM transmission system in accordance with the PJM-NYPP Interconnection Agreement Schedule 6.02. ***Credits:*** Total hourly charges are allocated as credits with monthly excess congestion credits.	***Hourly Transmission Congestion Credits***
1930 **2930**	**Generation Deactivation** (OATT Part V)	Revenues are collected for generators requesting retirement where PJM studies find reliability issues that require the generation to continue operating. Cost allocations to zonal load and firm withdrawal rights are determined by PJM based on the beneficiaries. These responsible customers pay the generation owners a share of the Deactivation Avoidable Cost Rate or the FERC-approved Cost of Service Recovery Rate. ***Charges:*** Charges are being collected for NRG Power Marketing, LLC resource Indian River Unit 4 based on a Cost of Service Recover Rate for dates June 1, 2022 through December 31, 2026. The monthly charges are allocated on a one-month lag. Based on PJM's assessment of the contribution to the need for, and benefits expected to be derived from, the facilities, the zonal percentage cost allocation is 100% to DPL.	***Generation Deactivation Charge Summary*** ***Generation Deactivation Refund Charge Summary***
1952 **2952**	**Deferred Tax Adjustment** (OATT Attachments H-7B, H-8A and H-17C)	***Charges:*** Each Network Customer that serves one or more end-use customers taking distribution service from PPL Electric Utilities Corporation, Duquesne Light Company, or PECO Energy Company under its applicable retail tariff on file with the Pennsylvania Public Utility Commission ("PPL Electric Distribution Customers", "Duquesne Electric Distribution Customers", and/or "PECO Energy Company Distribution Customers") shall pay a Monthly Deferred Tax Adjustment Charge. This charge permits PPL Electric, Duquesne Light and PECO Energy Company to recover a deferred income tax liability that is currently unfunded due to a Pennsylvania Public Utility decision to flow-through to customers certain income tax benefits.	***Deferred Tax Adjustment Charge Summary***
1957 **2957**	**Schedule 11A PJM Net** Manual 29, Section 2.4 OATT Schedule 11A	PJM Member request to purchase additional PJMnet connection(s) as described in the Open Access Transmission Tariff, Schedule 11A. PJM shall recover the costs of providing secure control center data communication ("PJMnet") in the manner set forth in this Schedule 11A from those Members who request additional PJMnet connections that are not required for reliability in the operation of the LLC or the Office of the Interconnection. ***Charges:*** The costs to be recovered under this Schedule 11A consist of the actual costs of owning, leasing, and operating PJMnet and all of its related assets.	
1980 **1985** **2980**	**Miscellaneous Bilateral** Manual 29, Section 2.4	PJM Settlement administers agreed upon requests between specific PJM Members to bilaterally adjust their billing statement, as either charges or credits.	
1995	**PJM Annual Membership Fee** Manual 29, Section 2.4	***Charges:*** The Primary/Voting Member, as described in PJM Manual 33, is charged an annual fee in for the upcoming calendar year membership.	

BLI ID	Billing Line Item	Description	Reports
1999	**PJM Customer Payment Default** (OATT Section 15.2.2)	The PJM Board of Managers may direct billing Default Allocation Assessment(s) to non-defaulting PJM Members to recover the amount(s) not paid or recovered from any net buyer. ***Charges:*** The default allocation assessment is equal to .1 * (1 / the total number of Members) + .9 * (the Member's gross activity as determined by summing the absolute values of the charges and credits for each of the Activity Line items as accounted for and billed for the month of default and the two previous months / the sum of gross activity for all eligible members) The assessment value of (0.1*(1 / number of eligible members)) shall not exceed $10,000 per Member per calendar year, cumulative of all defaults, or more than once per Member default if Default Allocation Assessment charges for a single Member default span multiple calendar years.	

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2024-00285 DATED MAY 16 2025

Annual Financial Impact of Duke Energy Kentucky Capacity Construct: Initial FRR Plan vs. RPM

FRR - RPM

DEK Portfolio Length

Long (Positive) or Short (Negative) Position

(Position = Length before Holdback or Short divided by Load Obligation)

BRA Clearing Price, $/MW-Day

Length	50	100	150	200	250	300	350	400	450	500
9%	$ 584,584	$ 855,998	$ 814,242	$ 459,316	$ (334,918)	$ (1,644,143)	$ (2,145,504)	$ (2,711,820)	$ (3,343,090)	$ (4,039,313)
8%	$ 591,008	$ 865,405	$ 823,190	$ 464,363	$ (338,598)	$ (1,662,210)	$ (2,169,081)	$ (2,741,620)	$ (3,379,827)	$ (4,083,701)
7%	$ 597,432	$ 874,811	$ 832,137	$ 469,411	$ (342,279)	$ (1,680,278)	$ (2,192,658)	$ (2,771,421)	$ (3,416,564)	$ (4,128,089)
6%	$ 603,856	$ 884,218	$ 841,085	$ 474,458	$ (345,959)	$ (1,698,345)	$ (2,216,235)	$ (2,801,221)	$ (3,453,301)	$ (4,172,477)
5%	$ 610,280	$ 893,624	$ 850,033	$ 479,506	$ (349,640)	$ (1,716,413)	$ (2,239,812)	$ (2,831,021)	$ (3,490,039)	$ (4,216,865)
4%	$ 616,704	$ 903,031	$ 858,981	$ 484,553	$ (353,320)	$ (1,734,480)	$ (2,263,389)	$ (2,860,821)	$ (3,526,776)	$ (4,261,253)
3%	$ 623,128	$ 912,437	$ 867,928	$ 489,601	$ (357,000)	$ (1,752,548)	$ (2,286,966)	$ (2,890,622)	$ (3,563,513)	$ (4,305,641)
2%	$ 649,846	$ 962,432	$ 937,758	$ 575,824	$ (259,211)	$ (1,648,851)	$ (2,168,485)	$ (2,758,070)	$ (3,417,604)	$ (4,147,089)
1%	$ 777,523	$ 1,214,345	$ 1,310,465	$ 1,065,883	$ 343,374	$ (939,401)	$ (1,343,291)	$ (1,817,846)	$ (2,363,065)	$ (2,978,948)
0%	$ 905,200	$ 1,466,257	$ 1,683,171	$ 1,555,943	$ 945,958	$ (229,950)	$ (518,097)	$ (877,622)	$ (1,308,525)	$ (1,810,806)
-1%	$ 543,387	$ 1,158,752	$ 1,426,534	$ 1,346,731	$ 779,344	$ (359,625)	$ (601,956)	$ (916,379)	$ (1,302,893)	$ (1,761,498)
-2%	$ (53,167)	$ 582,973	$ 868,087	$ 802,175	$ 243,852	$ (891,713)	$ (1,121,762)	$ (1,424,616)	$ (1,800,276)	$ (2,248,741)
-3%	$ (649,721)	$ 7,193	$ 309,640	$ 257,619	$ (291,640)	$ (1,423,801)	$ (1,641,568)	$ (1,932,854)	$ (2,297,659)	$ (2,735,983)
-4%	$ (1,246,274)	$ (568,587)	$ (248,807)	$ (286,937)	$ (827,133)	$ (1,955,889)	$ (2,161,374)	$ (2,441,092)	$ (2,795,042)	$ (3,223,226)
-5%	$ (1,842,828)	$ (1,144,366)	$ (807,255)	$ (831,493)	$ (1,362,625)	$ (2,487,977)	$ (2,681,180)	$ (2,949,329)	$ (3,292,425)	$ (3,710,468)
-6%	$ (2,439,382)	$ (1,720,146)	$ (1,365,702)	$ (1,376,049)	$ (1,898,117)	$ (3,020,065)	$ (3,200,986)	$ (3,457,567)	$ (3,789,809)	$ (4,197,711)
-7%	$ (3,035,935)	$ (2,295,926)	$ (1,924,149)	$ (1,920,605)	$ (2,433,609)	$ (3,552,153)	$ (3,720,791)	$ (3,965,805)	$ (4,287,192)	$ (4,684,953)
-8%	$ (3,632,489)	$ (2,871,705)	$ (2,482,596)	$ (2,465,160)	$ (2,969,102)	$ (4,084,241)	$ (4,240,597)	$ (4,474,042)	$ (4,784,575)	$ (5,172,196)
-9%	$ (4,229,043)	$ (3,447,485)	$ (3,041,043)	$ (3,009,716)	$ (3,504,594)	$ (4,616,328)	$ (4,760,403)	$ (4,982,280)	$ (5,281,958)	$ (5,659,439)

Positive *value means FRR is a* ***better*** *financial outcome than RPM Capacity Construct annually for the amount shown.*
Negative *value means FRR is a* ***worse*** *financial outcome than RPM Capacity Construct annually for the amount shown.*

Bi-lateral capacity to fulfill FRR shortfall assumed purchased at a premium of 1.25 x Auction Clearing Price
(Capacity owners have general reluctance to sell bi-laterial capacity)

Percentage of FRR Shortfall Subject to FRR Penalty:
25.00 25% 25%

Percentage of 3rd Incremental Auction Clearing Price of Base Residual Auction Price:
50.00 50% 50%

2025/2026 FRR Positon Portfolio Length = 77 MW/800.6 MW = ~9%; Bi-lateral Market Trading $85/MW-Day @ $92/MW-Day as of 7-19-2024; 2025/2026 BRA ultimately cleared $269.92/MW-Day

*Angela M Goad
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KY 40601-8204

*Minna Sunderman
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

*Debbie Gates
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

*Rocco O D'Ascenzo
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

*John G Horne, II
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KY 40601-8204

*Sarah Lawler
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

*Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45202

*Larisa Vaysman
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KY 40601-8204

*J. Michael West
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KY 40601-8204