COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC INVESTIGATION OF	)	
INTERCONNECTION AND NET	)	CASE NO.
METERING GUIDELINES	)	2020-00302

EAST KENTUCKY POWER COOPERATIVE, INC.
AND ITS OWNER-MEMBERS' BRIEF

Comes now East Kentucky Power Cooperative, Inc. ("EKPC") on behalf of itself and its sixteen member cooperatives, ("Joint Movants"), by and through the undersigned counsel, and hereby tenders its brief in compliance with the Commission's February 16, 2021 Order, respectfully stating as follows:

I. INTRODUCTION

On September 24, 2020, the Kentucky Public Service Commission ("Commission") opened an administrative docket to review the net metering interconnection guidelines to ensure consistency with statutory amendments and technology evolution since the Commission last updated the net metering interconnection guidelines in January 2009 in Case No. 2008-00169.[1] In an Order entered on February 16, 2021, the Commission took the additional steps of: (1) incorporating the record of a prior net metering administrative docket into the record of this proceeding;[2] and (2) directing the parties to file briefs on certain enumerated issues. Specifically,

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[1] *See In the Matter of: The Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity Up to Thirty Kilowatts*, Order, Case No. 2008-00169 (Ky. PSC Jan. 8, 2009).

[2] *See In the Matter of: The Electronic Consideration of the Implementation of the Net Metering Act*, Order, Case No. 2019-00356 (Ky. PSC Dec. 18, 2019).

the Commission invited parties to submit briefs discussing current and reasonably anticipated issues and concerns regarding the current net metering interconnection guidelines, and, separately, current and reasonably anticipated concerns regarding Federal Regulatory Energy Commission ("FERC") Order No. 2222[3] on Distributed Energy Resource ("DER") aggregation. The Commission explained that the information submitted will assist in evaluating the existing interconnection guidelines to identify whether any modifications are necessary, including consideration of adopting industry best practices, and also considering the physical and operational impacts anticipated to comply with FERC Order No. 2222. EKPC submits this brief on behalf of itself and its sixteen (16) owner-member distribution cooperatives.[4] Each distribution cooperative will be impacted by the outcome of this proceeding. Moreover, EKPC has been actively engaged in PJM's stakeholder process shaping PJM's implementation details to comply with FERC Order No. 2222.

II. OVERVIEW

As an initial matter, net metering and DER are mutually exclusive options for a retail customer of a distribution cooperative as it is inappropriate for a customer to be credited for any excess power generation by both its distribution cooperative and a DER aggregator. Moreover, there is no mandatory obligation for EKPC's owner-member distribution cooperatives to offer third-party DER aggregation under Order No. 2222, so there should be no interplay between their net metering programs and DER aggregation for wholesale market participation under Order No.

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[3] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators* (Order No. 2222) 85 FR 67094 (Oct.1, 2020), 172 FERC ¶61,247 (2020), *corrected*, 85 FR 68450 (Oct. 29, 2020).

[4] EKPC's owner-member distribution cooperatives are: Big Sandy RECC, Blue Grass Energy Cooperative, Clark Energy Cooperative, Cumberland Valley Electric, Farmers RECC, Fleming-Mason Energy Cooperative, Grayson RECC, Inter-County Energy Cooperative, Jackson Energy Cooperative, Licking Valley RECC, Nolin RECC, Owen Electric Cooperative, Salt River Electric Cooperative, Shelby Energy Cooperative, South Kentucky RECC, and Taylor County RECC.

2222. Nonetheless, EKPC offers suggestions for the Commission's consideration in this proceeding as well as for the Commission's advocacy both with PJM and, potentially, at the FERC when PJM submits its Order No. 2222 compliance filing.

III. KENTUCKY NET METERING

Kentucky's net metering program provides a suitable path to deploy renewable generation technology. Retail customer participation in EKPC's owner-member distribution cooperatives' net metering programs has increased significantly over the last five (5) years. In 2015, there were 172 installations totaling 1,175 kilowatts (1,154 kW solar and 21 kW wind). Participation grew to 664 installations in 2020, representing 6,128 kilowatts (6,103 kW solar and 24 kW wind). This 62% growth is expected to continue increasing given the reduced cost of technologies and tax incentives available for rooftop solar today. Additionally, there are close to two dozen known batteries co-located with solar facilities at retail customer sites participating in the net metering programs providing a back-up source of power to those customers during any experienced interruptions in grid-supplied power. The solar and wind installations are compensated pursuant to the net metering program at established tariffed rates. The back-up batteries are pursued independently by the retail customer. EKPC does not recommend any changes to the existing safety and reliability requirements or compensation provisions in the current distribution cooperative tariffs in this proceeding.[5]

[5] Pursuant to KRS 278.466(3), EKPC and its owner-members reserve the right to seek a change in the compensation rate for the net metering program in a future ratemaking process under KRS Chapter 278 "during a proceeding initiated by a retail electric supplier or generation and transmission cooperative on behalf of one (1) or more retail electric suppliers."

A. Existing Safety and Reliability Requirements are Generally Working Well

The current net metering program includes appropriate safeguards to ensure the safety of distribution cooperative employees and contractors who perform maintenance on the distribution system, as well as safeguards to ensure reliable delivery of power to all customers served by the distribution cooperatives. EKPC's distribution cooperatives have not identified any safety or reliability concerns with the programs; to date the current rules have ensured the safe and reliable operation of the distribution system. EKPC makes no recommendations with respect to these requirements.

The requirement that all installations be compliant with the distribution cooperatives' technical requirements, including those stemming from IEEE 1547 standards, the National Electric Code, and accredited testing laboratories such as Underwriters Laboratories,[6] has generally worked to ensure safety and reliability. Additionally, the tariffed requirement that customers must use the installed equipment in accordance with the manufacturer's suggested practices for safe, efficient, and reliable operation of the facility in parallel with the distribution cooperatives' distribution system remains appropriate as well.[7] Important dialog about all these requirements occurs in the application process when a retail customer requests to install equipment and participate in the distribution cooperatives' net metering programs.[8]

Current rules require the retail customer to agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, the distribution cooperative's

[6] *See* KRS 278.465(7).

[7] *See, e.g,.* Owen Electric Cooperative, Inc., Rate Schedule NM – Net Metering, Terms and Conditions for Interconnection ¶2, PSC Ky. No. 6, 1st Revised Sheet No. 101. EKPC's other owner-members have tariffs with substantially identical terms.

[8] Typically these conversations occur between the distribution cooperative and the resource installer. The distribution cooperative approves the equipment design before it is installed. After it is installed, the distribution cooperative may inspect and test the system to ensure it is built to the specifications agreed upon.

ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.[9] Current rules also require the customer to install an external disconnect switch ("EDS") adjacent to the distribution cooperative's meter (or otherwise ensure the location of the EDS is prominently noted on the meter).[10] Additionally, the rules allow the distribution cooperative to access the facility to perform on-site inspections to verify that the installation, maintenance and operation of the generation facility comply with the requirements of the tariff.[11]

Ensuring that a net metered generator does not back-feed onto the grid when system maintenance or an outage is occurring, or if the operation of the facility creates or contributes to a system emergency, is essential to protecting the lives of distribution cooperatives employees and contractors. The ability to disconnect the net metered generation facility that is not compliant with the tariff requirements is essential as such noncompliance jeopardizes the safety, reliability or power quality of the distribution cooperative's system.[12] When possible in non-emergency situations, a distribution cooperative will give the retail customer notice of the need to curtail or isolate the operation of their generators, but it is imperative that the distribution cooperative be authorized and able to take immediate action if safety or reliability risks are present. EKPC and its owner member distribution cooperatives urge the Commission to retain these essential elements of the net metering requirements and assure that they continue to reference the most recent editions of applicable codes.

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[9] *See, e.g,.* Owen Electric Cooperative, Inc., Rate Schedule NM – Net Metering, Terms and Conditions for Interconnection ¶5, PSC Ky. No. 6, 1st Revised Sheet No. 102.

[10] *See id.*, ¶8.

[11] *See id.*, ¶7.

[12] See *id.*, ¶9, PSC Ky. No. 6, 1st Revised Sheet No. 103.

B. Net Metered Customer Compensation

The 2019 amendments to the Kentucky Net Metering Act permit regulated utilities to compensate net metered customers differently than what was originally required.[13] Any new rate would apply prospectively on customers who apply for the net metering program and only after the Commission approves a new rate in a rate proceeding initiated by the utility.[14] Since any change in compensation is explicitly reserved to individual rate proceedings, EKPC is not addressing compensation in these comments, but reserves the right to make a proposal pursuant to KRS 278.466(3) at some point in the future.

IV. FERC ORDER NO. 2222

FERC Order No. 2222 seeks to harness the operational and market efficiency benefits of DER in organized wholesale electricity markets. The Order recognizes individual resources do not meet the minimum size threshold for market participation, but aggregation of them would. FERC defines DERs as any resource located on the distribution system, any subsystem thereof or behind a customer meter.[15] It does not prescribe what resources may comprise an aggregation but has identified that electric storage, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment may be among the types of resources aggregators may seek to combine in aggregations for wholesale market participation – for any market their operational capabilities would match the requirements (energy, ancillary services, and capacity).[16]

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[13] *See* 2019 KY. ACTS Ch. 101.

[14] *See* KRS 278.466(3).

[15] *See* Order No. 2222 at ¶114.

[16] *See id.*

The FERC acknowledged that including provision for behind the meter resources to participate in aggregations may intersect with retail net metering programs regulated by the Commission. Although the FERC prohibited double-counting DERs' contribution to a retail program and wholesale program, the FERC did not prohibit net metered customers from participation in wholesale market aggregations.[17] Rather, FERC left it to the retail regulator to decide whether any restrictions be placed on the retail net metering programs.[18] Moreover, the individual DER resources are not subject to FERC jurisdiction.[19]

The FERC also defined a new market participant role, that of a DER Aggregator, that would be considered a FERC-jurisdictional public utility.[20] The DER Aggregator may aggregate one or more DERs for participation in the PJM capacity, energy and ancillary service markets of PJM.[21] Much of the detail about how the Electric Distribution Companies ("EDC"), including electric distribution cooperatives, and DER Aggregators coordinate and share operational information with each other and PJM, as well as the registration and review of individual DER resources and aggregations by the EDC have yet to be determined.[22] These rules are subject to the

[17] *See id.* at ¶ 164.

[18] See i*d.* at 162, ("relevant electric retail regulatory authorities may decide whether to permit the customers of small utilities to participate in the RTO/ISO markets through distributed energy resource aggregations and relevant electric retail regulatory authorities continue to have authority to condition participation in their retail distributed energy resource programs on those resources not also participating in RTO/ISO markets").

[19] *See id*. at 96, ("[W]e decline to exercise jurisdiction over the interconnection of an individual distributed energy resource seeking to participate in RTO/ISO markets exclusively as part of an aggregation.").

[20] *See id.* at ¶ 42, ("to the extent a distributed energy resource aggregator makes sales of electric energy into RTO/ISO markets, it will be considered a public utility subject to the Commission's jurisdiction").

[21] *See id.* at ¶ 119, 129.

[22] *See id*. at ¶8 ("For each RTO/ISO, the tariff provisions addressing distributed energy resource aggregations must (1) allow distributed energy resource aggregations to participate directly in RTO/ISO markets and establish distributed energy resource aggregators as a type of market participant; (2) allow distributed energy resource aggregators to register distributed energy resource aggregations under one or more participation models that accommodate the physical and operational characteristics of the distributed energy resource aggregations; (3) establish a minimum size requirement for distributed energy resource aggregations that does not exceed 100 kW; (4) address locational requirements for distributed energy resource aggregations; (5) address distribution factors and bidding parameters for distributed energy resource aggregations; (6) address information and data requirements for distributed energy

compliance filing that PJM will submit to FERC in February of 2022. Additionally, the FERC left certain aspects to the retail regulator, such as the safe, reliable interconnection of DERs.[23]

A. <u>"Opt-In"</u>

Order No. 2222 does not automatically apply to all utilities. EKPC supported the National Rural Electric Cooperative Association's ("NRECA") advocacy in the FERC proceeding leading to Order No. 2222, and continued advocacy at FERC to provide for an "opt in" provision that recognized the operational challenges and overall economic burden that would be placed on small electric utilities, those whose annual electricity usage is less than 4 million MWh, should they need to comply with the provisions of that order. At present, each of EKPC's owner-member distribution cooperatives is under the size threshold required for the FERC's order to be applied absent the Commission's express authorization for the FERC's new rules to apply. In other words, aggregation of DERs for wholesale market participation is not mandated to be accommodated by EKPC's owner-members until such time as their size exceeds 4 million MWh annual electricity usage or the Commission otherwise expressly authorizes it to occur.

The FERC recently issued an order on rehearing further affirming the importance of the "opt in" for small utilities.[24] EKPC and its owner-member distribution cooperatives urge the

resource aggregations; (7) address metering and telemetry requirements for distributed energy resource aggregations; (8) address coordination between the RTO/ISO, the distributed energy resource aggregator, the distribution utility, and the relevant electric retail regulatory authorities; (9) address modifications to the list of resources in a distributed energy resource aggregation; and (10) address market participation agreements for distributed energy resource aggregators."

[23] *See id.* at ¶ 44 ("[T]he Commission recognizes a vital role for state and local regulators with respect to retail services and matters related to the distribution system, including design, operations, power quality, reliability, and system costs. As in Order No. 841, we reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements.").

[24] *See Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and independent System Operators*, 174 FERC ¶ 61,197, Docket No. RM18-9-002 (Mar. 18, 2021) ("Order No. 2222-A"), at 34 ("A RERRA that elects to not opt in under … Order No. 2222 does not intrude on the

Commission to refrain from exercising the "opt in" provision because to do so would expose the rural retail customers they serve to significant, unreasonable costs and potentially to service reliability issues.[25] These issues will be discussed in more detail below.

Although EKPC's owner-member distribution cooperatives fall under the "opt in" threshold, EKPC has been engaged with the EDCs in PJM and with the PJM stakeholder process to consider how the Order may impact distribution operations and distribution planning and what implementation rules may limit adverse impacts and minimize cost should at some future point Order No. 2222 would become applicable. Importantly, those discussions are highlighting the range of information technology and operations technology upgrades EDCs would need to invest in and undertake in order to fully accommodate DER aggregation as envisioned by Order No. 2222. The expense likely would be in the millions of dollars order of magnitude.

Moreover, these discussions have highlighted to EKPC the importance of the Commission having discretion to develop appropriate programs for distribution cooperatives to efficiently and effectively harness DER technology that would not entail the need for a costly build-out of the distribution cooperatives' information technology and operations capability for a "*Field of Dreams* build it they will come" type readiness seemingly envisioned by Order No. 2222.[26]

Commission's exclusive authority over practices that directly affect wholesale rates because the Commission chose to provide such an opt-in and expressly codified this opt-in in the Commission's regulations.").

[25] Not exercising the "opt in" also is consistent with the Commission's prior reservations of rights for Energy Efficiency and Demand Response in the PJM Integration Order. *See In the Matter of: Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection LLC*, Order, Case No. 2012-00169 (Dec. 20, 2012).

[26] Order No. 2222-A, Comn. Christie *dissent*, ("A rapid concentration of behind-the-meter aggregated DERs at various locations on the local grid will inevitably require costly upgrades to a distribution grid that has largely been engineered to develop power *from* the substation *to* end-user retail customers. Meeting the technologies challenges of this re-engineering of the local grid are not insuperable but there are substantial costs and we know these costs will ultimately be imposed on retail customers. States, public-power authorities and co-operatives are far better positioned to manage these costs and competing interests in their own areas of responsibility than FERC.")

B. System Technology, Process and Procedure Enhancements Necessary for Order No. 2222

Retail customers within the EKPC system are deploying DER, but not nearly at the same pace as customers in other parts of the PJM grid. A one-size-fits all approach for all utilities in PJM, therefore, is not appropriate. EKPC and its owner-member distribution cooperatives appreciate the flexibility afforded by Order No. 2222 to address DER deployment in small utilities in the most appropriate manner, managing cost and reliability in a manner approved by the Commission. The costs and reliability risks of a federal mandate exceed the benefits for the foreseeable future. Accordingly, EKPC encourages the Commission to refrain from exercising the "opt in" for its owner-member distribution cooperatives.

Due to the limited scope of DER deployment and range of technologies deployed, coupled with the fact that that deployment is one-off customer deployment and not deployment that coordinates the operation of multiple devices geographically spread across the distribution system, the distribution cooperatives today have not needed to embrace the unknowns and financial and technical risks associated with Order 2222 implementation.

EKPC has not conducted a detailed evaluation of each of its owner member distribution cooperatives, but from its limited evaluation, it was able to discern that significant investment would be necessary.

Before any DER is eligible for aggregating with other DERs under Order No. 2222, the DER must go through the distribution cooperatives' interconnection review process. The distribution cooperative will first review the individual DER interconnection to ensure it may reliably interconnect and inject power onto the system, identifying any distribution system upgrades the facility owner would be responsible to fund. Then the distribution cooperative will review the expected impacts of coordinated operation of DERs in an aggregation on the distribution feeder and on the substation. This second step has not yet been done by any of the distribution cooperatives. Moreover, it will not be a “once-and-done” evaluation either. As the composition of the aggregation changes, the distribution cooperative will need to assess whether each successive change will result in distribution system impacts that may need to be mitigated to ensure reliability.

It is difficult to predict how many interconnection requests a distribution cooperative will need to process. To date, the distribution cooperatives have managed PURPA applications and net metering applications without difficulty. The additional applications under an Order No. 2222 paradigm would create additional workload for the distribution cooperatives. Notably, the FERC was concerned that the volume would overwhelm PJM and the other RTOs, so it specifically reserved the interconnection review to the state process.[27] The distribution cooperatives may require additional staff and analytical tools to most effectively handle these processes.

The ability to monitor the state of the distribution in real time will increase in importance with greater penetrations of DER on the distribution system. Not all EKPC’s owner-member distribution cooperatives have Supervisory Control and Data Acquisition (“SCADA”). Of those that do, they may have it on their distribution substations but not on other distribution system elements down line. To be ready for third-parties to aggregate customer generation anywhere on their systems, the distribution cooperatives will need enhanced visibility of their systems, starting with SCADA in all distribution substations and including several key distribution elements.

Beyond SCADA, there will need to be communication infrastructure sufficient to relay the SCADA information to the distribution system operators. Today, there is very limited two-way, high-speed monitoring on the distribution system, and what exists is not tied to the currently

[27] *See* Order 2222-A at ¶ 80.

deployed SCADA. Currently the systems lack adequate communication bandwidth to automate this monitoring in real time, and the communications technology that would be required is expensive. To date, a few pilots have been deployed to monitor the output and voltage levels to inform distribution planning, but not real time operations.

Beyond visibility, distribution cooperatives will need to have a means to automatically or remotely take control actions in operating the distribution system to ensure the DER injections do not cause reliability problems for other customers on their systems. Today, the data collected via the SCADA does not automatically trigger operational actions. Any necessary action would be a manual intervention. Certain operational parameters may be alarmed and distribution system operators watch for their trigger; when such parameter alarms are triggered, the distribution system operator must manually intervene to address them. Relying on manual intervention is not a sufficient, reliable state of affairs when needing to accommodate to DER operation that the distribution cooperative does not control. Manual actions are not likely to keep pace with DER deployment or otherwise be exercised in sufficient time to prevent reliability issues. Moreover, manual intervention also incurs a cost. Every time a truck must roll to address the settings on capacitor banks at the substations or down line, a cost is incurred. An example to highlight the point is that today most of the capacitor settings are changed seasonally. They may need more frequent adjustment in an environment with greater DER deployment. Creating systems to allow automatic control would be expensive as there is currently no off-the-shelf product that may be deployed cost-effectively. Significant work would need to be undertaken to develop what would be needed and potentially could differ from distribution cooperative to distribution cooperative.

Simply put, the distribution cooperatives' energy delivery systems in their current state cannot reliably and safely manage significant DER resources in different geographical locations, nor a multiplicity of such aggregations that may be created. The wholesale market participating DERs could act in a manner causing distribution system operational issues, and the distribution system is not currently configured and operated in a manner allowing the distribution cooperative to automatically respond to operational concerns nor effectively manually respond to operational concerns. The distribution system was not designed for the environment which FERC now seeks to develop and significant "catch-up" will be required to re-design, re-engineer and re-build the network. Without a clear benefit, such efforts would likely be labeled as "wasteful duplication" under any meaningful analysis under KRS 278.020.

For example, without real time visibility and automated or remote means to operate the distribution system in response to the operations of aggregated DER, there are several scenarios that demonstrate the challenge distribution cooperatives may face. The scenario provided below is not the only operational scenario that may impact customers not participating in DER aggregations. It is provided to explain the significant reliability and cost concerns that EKPC's distribution cooperatives would face if they needed to accommodate third-party aggregation of DER on their systems for wholesale market participation.

> Scenario: A DER aggregation operates in a manner that impacts the voltage on one distribution feeder, resulting in a voltage regulator not set-up for bi-directional power flows mis-operating and exposing other consumers to voltages outside the standard voltage band, leading to interruptions or damaged equipment. Reliability impacts would not be limited to the customers who participate in a DER aggregation, but will spread to other customers served by the distribution cooperative. To prevent this, without having deployed other expensive technology that would allow for bi-directional voltage regulation, the distribution cooperative would need to manually override PJM's dispatch of the DER aggregation. However, practically speaking, it would be very challenging today to identify this event before it materialized in real time, and hence, difficult to avoid through a manual override of PJM's dispatch. From an operations perspective, distribution cooperatives do not have a system or process in place today to do dynamic, real-time

> operations analysis to prepare for a potential need to "override" a PJM dispatch of a DER aggregation. They would need to develop the tools and processes to evaluate DER impacts, including forecasting the potential operation of the resources based on sun, wind and other weather or system conditions expected in real-time. There also would need to be consideration of whether additional employees and additional skill sets would be needed for these functions. The bottom line is that without substantial investment which will materially impact ratepayer's rates, compliance with FERC Order 2222 is likely to make the electric grid *less* safe and reliable.

Moreover, from a distribution system planning perspective, the change in system use resulting from the injections, which largely do not offset consumption because they are made to supply power to the wholesale electricity system, may require additional distribution grid enhancements or result in more rapid degradation of distribution system equipment.

> Scenario: A DER aggregation results in two-way power flows needing to be accommodated by distribution transformers. However, these transformers were designed for unidirectional power flow, not also for reverse power flows. The result is that the use case expedites the end of life of the transformers by up to 25%.[28]

This outcome, of course, represents additional significant cost and consideration of how to allocate such costs so as to not create an additional burden on customers who do not participate in DER aggregations may be necessary.

It also will be likely that the distribution cooperatives will need to update their settlement systems to account for the billing associated with DER aggregation. An example to highlight a billing complexity is battery storage. When batteries charge to be used to offset retail customer consumption, the electricity they use will be billed at a retail rate.[29] However, when batteries

[28] *See* "Distributed Energy Resources (DERs): Impact of Reverse Power Flow on Transformer," P. Upadhyay, J. Kern, V. Vadlamani (Oct. 2020) at https://energycentral.com/system/files/ece/nodes/463672/der_reverse_power_flow_impacts.pdf.

[29] *See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 162 FERC 61,127 (Feb. 15, 2018) at ¶ 289.

charge for injection into the grid for participation in the wholesale market, they will be billed at the wholesale energy price applicable for the injection.[30] The settlement systems deployed across EKPC's owner-member distribution cooperatives are not all the same. There are two different systems used by the distribution cooperatives, and there are different versions of those systems currently deployed. It is not an insignificant undertaking in time or money to work with the providers of those systems to make consistent changes to the settlement systems. Both the cost of the technology and process development and time to effectuate them would need to be factored into any distribution cooperative's readiness for what is envisioned by Order No. 2222. It is anticipated that the cost would be significant – again, in the order of magnitude of millions of dollars for each cooperative. Effectively, to operate a distribution system in a safe and reliable manner with DER aggregations as envisioned in Order No. 2222, the distribution cooperative would be required to plan, implement technology on its system, and operate the distribution system in a dynamic manner in a similar fashion to how RTOs plan and operate the transmission system today.

C. Suggestions Should Any Distribution Cooperative Grow to Exceed 4 million MWh Threshold

Notwithstanding the current ability of EKPC's distribution cooperatives to avail themselves of the "opt in" shield from Order No. 2222 application, EKPC believes it is prudent to think long term and to consider what might be needed in the future. Given their current annual energy usage, EKPC does not envision that any of its owner-member distribution cooperatives will be faced with this decision in the near term, nor that they all would cross Order 2222's threshold at the same time in the future. Additionally, each cooperative is in a different stage of deploying

[30] *See id.*

the type of operations control technology that will be necessary to reliably manage distribution system operations with DER activation occurring for grid injection based on PJM's dispatch, not the distribution cooperative's directive. Should at any point in the future one or more of EKPC's owner-member distribution cooperatives become fully subject to implementing Order No. 2222, EKPC believes that the following issues will need to be addressed by the Commission to best ensure reliability, safety, and to ensure there is no cost-shifting to customers who are not participating in a DER aggregation.

- The Commission should condition participation in the distribution cooperative's net metering or other DER programs, and any other narrowly tailored programs that may be developed to harness DER deployment discussed above, on the customer not also participating in a wholesale market DER aggregation. Consistent with FERC Order 2222, double-counting through participation in a net metering program and a PJM DER aggregation program should be expressly and clearly prohibited.[31]
- To effectuate the conditioned participation in the retail programs, the Commission should advocate in the PJM stakeholder process and in the compliance filing proceeding at FERC that the Commission's prohibition should be honored through the DER aggregation registration process such that EKPC or the distribution cooperative could indicate that a customer included in an DER aggregation may be disallowed the duplicative participation. The metering and accounting that would be required to ensure the same MWh was not utilized for both a retail and wholesale purpose entails more cost that benefits. Moreover, from a practical perspective, the

[31] *See* Order No. 2222 at ¶ 162; Order No. 2222-A at ¶63-64.

net metering program cannot parse injections for the net metering program from injections for another purpose. KRS 278.465(2)(c) sets 45 kW as the upper capacity limit of the net metering resource but does not establish a limit on the actual injection that would count toward net metering; Rather, all injections from a net metered generator is accounted for as a net metered injection. There is no level at which the injection ceases to be for purposes of the net metering program. Therefore, it is be reasonable to presume that all injections made are done so under the net metering provisions. To also seek wholesale market compensation through a DER aggregation in the wholesale market would result in the customer receiving double-payment for the same service while not providing double the reliability or market efficiency benefits. Additionally, such double-counting may result in a mismatch between the expected load EKPC would expect to supply and what it actually must supply in real time operations.

- The Commission should expand the scope of the net metering interconnection guidelines to indicate that compliance with them is necessary for any customer-sited resource intending to participate in a DER aggregation in the PJM market. For DER aggregation projects exceeding the statutory capacity cap for net metering, interconnection requirements should be worked out to the utility's satisfaction regarding safety, reliability and grid integrity in a manner consistent with existing codes, standards and good utility practice.
- Interconnection guidelines accommodating the FERC Order No. 2222 would need to include provisions for resource technologies not currently addressed by the guidelines, such as battery storage and hybrids (storage + another technology like

solar or wind) and any other technologies reasonably anticipated to be deployed in Kentucky.

- In addition to updating the interconnection guidelines, EKPC encourages consideration of the "smart inverter" settings that customer-sited generation should use. IEEE 1547 provides flexibility for setting the standards. PJM had worked with EDCs to consider what settings may also account for transmission grid reliability needs that may be important to consider as inverter-based resources proliferate and perhaps concentrate on the grid. Such decisions may not be needed in the near term as the deployment is low, but it may be something to watch for future action. The current requirement that the installations comply with IEEE 1547 should avoid the need for costly retrofits in the future to maintain system reliability. Thinking about the appropriate settings likewise may provide benefits.
- Updated interconnection requirements would need to be incorporated into the utilities' net metering agreement templates. The updates would build upon the net metering agreement reliability and safety provisions, to clarify the roles and responsibilities of customers participating in DER aggregations. The updates also may require the DER participating in aggregations to bear cost responsibility for use of the distribution facilities generally to deliver the injected energy to the transmission system for participation in the PJM market, in addition to cost responsibility for the facilities necessary to interconnect the distributed resource and support the reliable injection of power individually and as part of an aggregation with other DERs.

- EKPC identified above illustrations of significant infrastructure upgrades, systems and process enhancements that may be required should the distribution cooperatives need to be fully compliant with all that is envisioned in Order No. 2222. Significant effort would need to be undertaken to determine specifically what would be required for each of EKPC's owner-member distribution cooperatives to be ready to comply with the requirements of Order No. 2222. Furthermore, consideration of which customers should bear these costs and how they may best be recovered will be important as there likely will be segments that cannot or otherwise do not wish to deploy DER. Equitable cost assignment is important, especially given increased challenges to ensure overall energy costs are affordable for all cooperative customers.
- EKPC and its owner member distribution cooperatives encourage the Commission to advocate in the PJM process and potentially at FERC in support of rules that allow for a reasonable implementation time for electric distribution cooperatives that may in the future grow to a size of over 4 million MWh annual usage, the trigger for Order No. 2222 requirements to become applicable. Instead of having the requirements automatically trigger at that time, PJM's compliance filing should provide for a reasonable transition to account for the readiness activities the distribution cooperative would need to undergo. Readiness may involve distribution system enhancements, IT and settlement system upgrades as well as an array of process, procedure and training changes. All of which will take time and money to effectuate. Moreover, it is challenging to state today how much time would be necessary for a distribution company to be ready. EKPC suggests that

PJM's compliance filing should allow for a determination of the appropriate transition period to accommodate the distribution company proceeding to a readiness state after the distribution cooperative crosses the 4 million MWh annual energy usage threshold in two consecutive years. This recommendation acknowledges that it will be important that the utilities' growth is sustainable, and that the appropriate transition period post that sustained growth needs to be based on the unique facts and circumstances of the distribution cooperative.

V. CONCLUSION

EKPC and its owner-members appreciate the Commission being proactive in seeking thoughts and perspectives on the net metering interconnection guidelines and the DER aggregation rule, Order No. 2222, issued by the FERC. EKPC and its owner-members believe that no changes need be made to the net metering interconnection rules at this time. The safety and reliability measures in the net metering program have been adequate for the deployment of behind the meter generators and as long as the requirements refer to the latest editions of the applicable codes and standards, net metering installations should be safe for customers and utility personnel alike. With regard to DER aggregation, several factors will need to be addressed for any Kentucky utility that must comply with Order 2222. Although no EKPC distribution cooperative is of the size where compliance with Order 2222 is mandatory, the suggestions contained in these comments are offered to inform the Commission in its advocacy in the PJM stakeholder process and at FERC to ensure that the cost and reliability implications are mitigated to the fullest extent possible. EKPC looks forward to further constructive participation in this administrative case as the Commission may direct.

Done this 19th day of April, 2021.

Sincerely,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the documents being filed in paper medium; that the electronic filing was transmitted to the Commission on April 19, 2021; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that a copy of the filing in paper medium paper copies of this information will be hand-delivered to the Commission within thirty (30) days of the lifting of the present State of Emergency relating to the COVID-19 pandemic.

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