May 29, 2024

Filed Electronically

Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Distributed Energy Resources Participation in Wholesale Markets
Docket No. L-2023-3044115

Dear Secretary Chiavetta:

On behalf of the Coalition Advocating DER Regulation Efficiency ("CADRE"), I am enclosing comments in response to the ANOPR Order issued by by the Pennsylvania Public Utilities Commission on the issue of Distributed Energy Resources Participation in Wholesale Markets.

In addition to me, could you please add the following members of the Coalition to the service list in this proceeding:

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Thank you for your consideration of these comments.

Sincerely,

Frank Lacey
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITIES COMMISSION

Distributed Energy Resources Participation in Wholesale Markets	: :	Docket No. L-2023-3044115

COMMENTS OF THE COALITION ADVOCATING DER REGULATION EFFICIENCY ("CADRE") IN RESPONSE TO THE ANOPR ORDER SEEKING COMMENT ON DISTRIBUTED ENERGY RESOURCES PARTICIPATION IN WHOLESALE ELECTRICITY MARKETS

I. Introduction

The Coalition Advocating DER Regulation Efficiency ("CADRE") is a group[1] of many of the largest distributed energy resource ("DER") service providers in the country. CADRE includes demand response providers, electric generation suppliers ("EGS"), retail energy providers, solar energy developers and trade associations representing industries focused on improving energy markets. These companies intend to be DER Aggregators ("DERA") and/or DER service providers when the PJM market permits.

These Comments are in response to the Advanced Notice of Proposed Rulemaking issued by the Pennsylvania Public Utility Commission ("PUC" or "Commission") on April 22, 2024, and published in the PA Bulletin on March 30, 2024.[2] CADRE applauds the Commission for

[1] CADRE is an ad hoc coalition of DER service providers including Sunnova Energy, IGS, Engie, Voltus, and CPower Energy, and also includes the Solar Energy Industries Association ("SEIA"), Advanced Energy United ("United") and the Advanced Energy Management Alliance ("AEMA"). These comments reflect the opinions of the Coalition and not necessarily the views of any one member.
[2] Pennsylvania Public Utility Commission, Advance Notice of Proposed Rulemaking Order, *Distributed Energy Resources Participation in Wholesale Markets,* Docket No. L-2023-3044115, February 22, 2024 ("ANOPR Order"), 54 Pa.B. 1668, March 30, 2024.

undertaking this rulemaking process. The existing regulatory framework in Pennsylvania will require upgrades to support robust DER aggregations participating in the PJM market, especially those comprised of DERs owned by residential customers for whom scale regulatory improvements in metering, data transfer and billing will be very important.

CADRE is participating in this rulemaking process to seek efficient regulations that will benefit the market and the customers. Our recommendations include revisions of existing regulations, removal of some regulations that are out of date or otherwise unnecessary, and the incorporation of others. As the Commission considers new regulations, we ask that it keep in mind that electric distribution companies ("EDCs") are regulated monopolies that have an obligation to provide services to their customers. That obligation persists, even as customer needs evolve. Regulations that obligate the EDCs to provide their customers with robust and modern services, consistent with the technologies available in today's digital economy, will unleash a powerful dynamic in the market that will benefit all electricity customers in the Commonwealth. It is in this area where we seek strong Commission leadership. We ask that the Commission compel the EDCs to enhance their capabilities and services. The Commission will need to adopt regulations on the EDCs to set standards for how the EDCs will interact with DERAs to ensure the efficient deployment of DERs. These include, among other issues, upgrades to interconnection, metering, data transfer and billing technologies and practices. We understand that DERAs will need to act responsibly in this market. But without regulations to drive EDCs to modernize their systems, technologies and behaviors, the DER market in Pennsylvania will fall far short of its potential.

Allowing DERs to participate in the wholesale electricity market is a transformational step facilitated by the Federal Energy Regulatory Commission ("FERC") through its Order No.

2222.[3] DER aggregation will provide substantial consumer and market benefits, many of which are described below. The Joint Statement Chairman DeFrank and Vice Chair Barrow issued concurrently with the ANOPR Order ("Joint Statement") recognizes this value, stating that "Distributed resources provide the possibility for those who were traditionally consumers to play an active role in ensuring electric reliability and resiliency for themselves and their neighbors, and often in a less expensive way than traditional large generation that requires delivery infrastructure."[4]

To maximize the value of DERs, aggregators will need to routinely communicate important information to DER owners regarding their devices. Aggregators may be controlling electrical equipment, EV charging, energy storage devices, air conditioning, inverters, or other controllable resources. Aggregators will need to receive information from EDCs in a real-time or near real-time manner and react to that information to satisfy PJM's market requirements and to best benefit the consumer. At the end of a day, a week, or a billing period, an aggregator will need to explain the actions it took, the energy that was used or saved, the market pricing and the overall results for the customer over the period. Data latency, burdensome regulations, archaic rules that don't accommodate the digital economy and outdated billing requirements will severely stifle the innovation and communications required to effectively manage DER products and services. As the Commission noted in its ANOPR Order, FERC required PJM to "coordinate with the [EDCs] and [PUC] to establish protocols for sharing metering and telemetry data, and

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[3] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations & Independent Systems Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[4] Joint Statement of Pennsylvania PUC Chairman Steven M. DeFrank and Vice Chair Kimberly Barrow, Distributed Energy Resources Participation in Wholesale Markets, Docket No. L-2023-3044115, February 22, 2024.

that such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity."[5] CADRE implores the Commission to be open-minded and forward thinking about DER products and services when it evaluates the regulatory framework in Pennsylvania. CADRE believes that the Pennsylvania DER regulation model will likely become a framework for other states.

The Joint Statement asked commenters "to include any information about how similar changes may be implemented in other states." CADRE pledges to work with Pennsylvania and other states to seek a unified regulatory platform for DER aggregation. CADRE has recently filed comments in New Jersey in response to a Request for Information on the topic of DERs participating in wholesale markets issued by the New Jersey Board of Public Utilities ("NJBPU").[6] In that response, we encouraged New Jersey to look to the Pennsylvania rulemaking process in this docket and raised with the NJBPU all the issues the Commission has included in this ANOPR. We recognize that the cross-border rules will not be identical, but we endeavor to achieve as many similarities as possible. The value to customers that operate across state boundaries will only be enhanced by complementary state-level DER regulations.

II. Background: DERs Present a Transformational Opportunity for the Commission

The introduction of DERs and DER aggregations into wholesale electricity market marks a transformational moment in electricity markets. If allowed to flourish, as envisioned by FERC

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[5] ANOPR Order, pp 4-5, citing Order No. 2222, Para 270.

[6] New Jersey Board of Public Utilities, *In the Matter of New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets*, Docket No. EO24020116.

in Order No. 2222, DERs can provide emissions reductions, result in lower costs for all consumers, increase reliability and resiliency and can be incorporated into the wholesale electricity markets without using ratepayer funds. In a presentation to the Michigan PSC Demand Response Stakeholder Group, Collaborative Utility Solutions ("CUS") states unequivocally that "Implementation of 2222 is the single biggest opportunity of our lifetime for meaningful impact across the entire industry to lower cost, improve resiliency and take advantage of these new clean energy resources called DERs."[7] They remind us that DERs present "a mammoth opportunity for our industry – not a burden."[8]

Customers are willing and able to provide electricity resources; service providers are willing and able to aggregate and bring these resources to the market; and technologies to reduce emissions and facilitate aggregations are readily available in the market. Federal regulation fully supports the deployment of DERs and DER aggregations in wholesale electricity markets. The remaining obstacles that could mitigate full deployment of DER and DER aggregations are potential opposition from certain stakeholders in the Commonwealth, reluctance from the utilities, and/or overly burdensome or inappropriate retail regulations. We urge the Commission to be forward-looking, yet prudent when looking at these issues. It will take thoughtful regulatory innovation to capture the full value of DER, but as noted above, the opportunity is

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[7] See: www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/DR-DER-Aggregation/DR-DER-Aggregation-CUS-Presentation-2-22-24.pdf?rev=e5e9dd35cf99499896021c10b1b5e293&hash=E7F43CFA1D29132C622BC5397FB2C720, p. 6. (Internal quotations omitted.) CUS is a is a non-profit 501(c)6 organization that was created to advance and support the electric industry by developing, enhancing access to, and enabling data and technology regarding DERs to support a clean energy future.

[8] *Id.*, p. 3.

mammoth – perhaps the biggest opportunity of our lives. Critically, the Commission should not erect barriers to full implementation of DER and DER aggregations.

CADRE is not advocating for a "no regulation" approach. CADRE believes well-designed regulations will facilitate full deployment of DER and DER aggregations. It will be imperative to the success of the DER market for the Commission to impose upon the EDCs rules compelling effective EDC interaction, consistent with the needs of an advanced energy market, with DERAs to ensure the efficient deployment of DERs. It is important for the Commission and stakeholders to take a comprehensive view of the markets and redesign some existing regulations, perhaps add regulations to govern certain aspects of the market and potentially eliminate old or constraining regulations.

The Commission should understand that a comprehensive DER program can provide customers with the consumer products and services that nearly all regulators have longed for since the advent of retail choice – real time energy management, enabling customers to be actively involved in their energy management, reducing costs and aiding in emission reductions, reliability and grid resilience. DERs are transforming the traditional one-directional flow of electrons from a power plant to a customer into a bi-directional flow of electrons between a customer and the grid, enabling robust energy products and services. With thoughtful regulation and market design, customers will be able to participate in PJM's energy, capacity and ancillary services markets, reducing their costs as well as reducing energy costs for non-participants in the market. We also believe that the Commission can provide regulatory guidance that would enable net energy metered ("NEM") customers to continue to receive compensation under the retail tariffs currently in place, but also to provide incremental benefit to the wholesale market, that would not amount to double compensation, through use of device-level meters.

Pennsylvania was an early leader in developing retail choice markets. Pennsylvania was a leader in adopting renewable energy standards for energy companies. Now, it is one of the first states to take a comprehensive review of the state jurisdictional components of a DER market. We encourage the Commission to enable this transformation for consumers and to be a leader on these issues, and to the extent possible, share information across state lines.

III. Threshold Issues

The ANOPR sought input on 13 different topics. Section IV of these Comments addresses each of those topics in turn, with each of the Commission's individual questions included as sub-headings. We have applied section numbers to each of the Commission's questions for ease of reference. Before we get to the specific Commission questions, we include this Section III, which identifies two threshold issues that we feel the Commission must also address in order to facilitate DER participation in wholesale electricity markets.

III. A. Definitions of EGS and DER Providers

CADRE recommends that the Commission adopt new regulations that make clear that DERAs, which aggregate customer-owned resources for the purpose of selling electricity into ***wholesale*** markets, are not subject to existing regulations arising out of the Electric Generation Customer Choice and Competition Act ("Choice Act"),[9] which governs the ***retail*** sale of electricity to end-use customers.

[9] 66 Pa.C.S. §§ 2801–2815.

When it was enacted in 1996, the Choice Act was "transformative"; it sought to create a competitive market for retail sales of electricity by recognizing a variety of new market participants in that space. But the scope of the Choice Act and the role of these new market participants concerned the sale of electricity to end-use customers in retail markets. Indeed, the Declaration of Policy embedded in the Choice makes clear that a central purpose of the act was "to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth."[10] Of course, DERAs do not sell electricity to end-use consumers in retail markets. It's just the opposite. DERAs allow consumers to forego consumption of electricity in retail markets and ***sell that electricity into wholesale markets***. The Commission should recognize this distinction and clarify that the Choice Act and the regulations surrounding EGSs have no application to DERAs.

The Commission should likewise clarify that DERAs are not included among the market participants created by the Choice Act. For instance, the Choice Act defines an "Aggregator" and "Market Aggregator" as an "entity, licensed by the commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers."[11] DERAs do not take title to electric energy as an intermediary for sale to retail customers. Similarly, "Broker" and "Marketer" are defined in the Choice Act as an "entity, licensed by the commission, that acts as an agent or intermediary in the sale and purchase of electric energy but that does not take title to electric energy."[12] DERAs do not act as an intermediary in the sale and purchase of electric energy, especially when viewed in the comprehensive context of the Choice

[10] 66 Pa.C.S. §§ 2802 (14).
[11] 66 Pa.C.S. §§ 2803.
[12] *Id*.

Act. Finally, the Choice Act defines "Electric Generation Supplier" and "Electricity Supplier" in part, as "a person or corporation …, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company or that purchases, brokers, arranges or markets electricity or related services for sale to end-use customers …."[13] DERAs do not market or sell electricity to end-use customers.

Because the Choice Act – a 1996 piece of legislation – did not envision bi-directional flow of electricity or the existence of DER products and services much less DER aggregations, CADRE recommends that the Commission create a few new definitions. The first is "Distributed Energy Resource." In Order No. 2222, FERC used the following: "Distributed energy resource … means any resource located on the distribution system, any subsystem thereof or behind a customer meter." The second recommended definition is for "Distributed Energy Resource Aggregator" which FERC defines as "the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators."[14] Other proposed definitions are listed in the recommendation section below. CADRE recommends that the Commission adopt these, or similar definitions and make them clearly differentiated from the retail-related market participants identified in the Choice Act.

CADRE recommends that the Commission create a new Section 78 in Title 52 of the PA Code that would be titled "Distributed Energy Services." We believe a new Section is

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[13] *Id*.
[14] 18 C.F.R. §§ 35.28(b)(10) and (11).

appropriate in this location, in Subpart C, under Fixed Utility Services. The regulations drafted to accommodate DER and DER aggregation participation in wholesale markets will be primarily directed at the EDC and EDC/Aggregator interactions. 52 PA Code § 78.1 would be the definitions section.

CADRE recommends against including DER-related regulations in 52 PA Code § 54, the Customer Choice sections of the regulations. We believe inclusion in this existing section will lead to confusion because as noted, DERAs do not sell retail energy to end-use consumers and 52 PA Code § 54 is dedicated to rules governing those sales. To be clear, an EGS is not a DERA. A DERA is not an EGS. There is nothing that prohibits a company from offering both services, but there is nothing fundamental that would require either an EGS or a DERA to offer the services of the other.

This distinction is made completely clear by a recent decision from the Commission in the License Application of Enerwise Global Technologies, LLC d/b/a CPower for Approval to Offer, Render, Furnish, or Supply Electricity or Electric Generation Services in Docket No. A-2019-3009271.[15] In this case, the Commission rejected an application from a demand response provider to become licensed as an EGS. The order drew a distinction between being a "CSP" (a term defined in Act 129 as a service provider to utilities) and an EGS. The Commission concluded that to "allow a [Demand Response Provider] that does not provide EGS services to customers, such as Enerwise, to become licensed as an EGS would require that all similarly situated entities that provide similar services to apply for an EGS license, making the registry

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[15] Final Order, Pennsylvania Public Utility Commission*, License Application of Enerwise Global Technologies, LLC d/b/a CPower for Approval to Offer, Render, Furnish or Supply Electricity or Electric Generation Service*, Docket No. A-2019-3009271, October 7, 2021. ("Enerwise Order").

required by Section 2806.2 of the Code superfluous and unnecessary."[16] The Commission also recognized that:

> "Enerwise's service is not 'electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an electric distribution company.' 66 Pa.C.S. § 2803. While 'related services' for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an EDC is arguably ambiguous, we agree with PPL that the definition of EGS must be read in the context of its enactment. PPL explains, and we agree, that the EGS definition was enacted as part of the Electricity Generation Customer Choice and Competition Act of 1996, 'which was wholly focused on creating access to a competitive market for electric generation.' PPL Comments at 3. The Commission has similarly stated, '[t]he purpose of the Act was to move toward greater competition in the electricity generation market in an effort to lower electric generation rates for the citizens of this Commonwealth.'"[17]

DER aggregations participating in wholesale markets include demand response and other resources. The Commission, absent new rules adopted in this proceeding, would logically reach the same conclusion in the future, which necessitates the rise for adding new definitions to the Pennsylvania Code. The definitions proposed below are similar, but not exactly the same as the definitions in the PJM tariffs, cited by the Commission in the ANOPR order.[18] While we would not oppose the use of those definitions, we believe these are more consistent with Pennsylvania-specific market needs. The important issue is to carve out DER-specific definitions in the regulations so that DER and DER aggregations can participate without constraints in Pennsylvania.

CADRE Recommendation: Add a new Section 78.1 to Title 52 of the Pa. Code.

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[16] Id., p. 7.
[17] Id. pp. 8-9.
[18] ANOPR Order, pp. 6-7.

- **52 Pa. Code § 78.1 Definitions**
    - **Component Distributed Energy Resource – any one distributed energy resource that is a part of a Distributed Energy Resource Aggregation.**
    - **Distributed Energy Resource -- any electric resource located on the distribution system, any subsystem thereof or behind a customer meter.**
    - **Distributed Energy Resource Aggregation -- a group of one or more DER that are joined together for the purpose of participation in the capacity, energy and/or ancillary service markets of the regional transmission organization and/or independent system operator.**
    - **Distributed Energy Resource Aggregator – an entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organization and/or independent system operator.**

III. B. DER Aggregator Licensure in Pennsylvania

CADRE is not opposed to having some type of DER licensing requirement to offer DER Aggregation services to consumers. Licensure could be a requirement for DERAs to access customers' utility data and establish standards for DERA use and protection of such data. One of the most significant needs for the DER community from the Commission is for the Commission to ensure that DERAs have a reliable stream of customer data (discussed in more detail below). It is this need for customer data that prompted Enerwise's application to become licensed as an EGS. According to the Commission, "Enerwise acknowledge[d] that it is only applying for an EGS license in order to obtain utility data on behalf of its customers so that it can verify customer performance in demand response programs and assist the customer in analyzing their usage and capabilities."[19] CADRE reminds the Commission, however, that DERA Services are largely wholesale services, not retail services. We suggest that licensing requirements be limited

[19] Id. p. 4, citing Enerwise's EGS Application at Section 4.b.

to evidence of technical merit to perform the Commission-jurisdictional tasks for which it is seeking licensure. CADRE is opposed to some of the licensing requirements established for EGS such as financial surety requirements. Financial requirements are levied on DERAs by PJM at the wholesale level under federally approved tariffs and protocols and are therefore redundant at the state level.

CADRE Recommendation: Add new Sections 78.31 through 78.38 to Title 52 of the Pa. Code in a Licensing Subchapter that are similar to the licensing requirements for EGSs.

- **§ 78.31 Definitions**
  - **Applicant—A person or entity seeking to obtain a license to exchange customer data with EDCs and to provide or engage in other state-jurisdictional services to provide distributed energy resource aggregation services.**
  - **Code—The Public Utility Code (66 Pa. C.S. Part I).**
  - **EDC—Electric distribution company.**
  - **Distributed Energy Resource Aggregator – an entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators.**
  - **License—A license granted to a Distributed Energy Resource Aggregator under this subchapter.**
  - **Licensee—A person or entity which has obtained a license to engage in state jurisdictional activities in support of providing Distributed Energy Resource services.**
  - **Renewable resource – as defined in section 2803 of the code.**
- **§ 78.32 Application process – This section should mirror § 54.32, except for the following:**
  - **All references to EGS should reference DER Aggregator**
  - **All references to retail sales of electricity should reference DER Aggregation Services**
  - **Sections (g) and (h) should not be included as they are irrelevant.**
- **§ 78.33 Application form – This section should mirror § 54.33, except for the following:**

- **§ (a)(8) should not be included. For DER aggregators, their services, including the provision of any bills, would not be subject to Commission jurisdiction. EGSs that provide DER Aggregation services will need to be licensed as an EGS so those standards would apply.**
    - **§ (a)(9) should not be included. There should be no publication requirement. DER Aggregators provide service that is FERC jurisdictional. EGSs that provide DER Aggregation services will need to be licensed as an EGS so those standards would apply.**
- **§ 78.34. Change in organizational structure or operational status. This section should mirror § 54.34.**
- **§ 78.35 Approval. This section should mirror §54.37, except for the following:**
    - **Section (a)(1) should read "The applicant is fit, willing and able to properly perform the service proposed in conformance with applicable provisions of the code and lawful commission orders and regulations.**
    - **Section (a)(2) should not be included.**
- **§ 78.36 Regulatory assessments. This section should mirror § 54.38.**
- **§ 78.37 Transfer or abandonment of license. This section should mirror § 54.41, except the references to the Choice Act should be removed. Also, section (b) regarding the abandonment of a license should not be included as there would be no impact on the EDCs, customers or default service providers if a DER provider left the market.**
- **§ 78.38 License suspension; license revocation should mirror §54.42, except for the following:**
    - **(a)(2) should not be included**
    - **(a)(3) should be revised to eliminate references to taxes owed by EGSs.**
    - **(a)(4) should not be included as it refers back to the Choice Act.**
    - **(a)(6) should not be included (see discussion of § 54.43 Standards of Conduct below)**
    - **(a)(7) should be edited to eliminate the reference to the Choice Act.**
    - **(a)(9) should not be included as it refers back to the Choice Act.**

§ 54.35. Publication of notice of filing should not be carried forward in this new chapter related to DER and DER aggregations. In many instances, DER services are already being provided in the Commonwealth, limited to only demand response at this time, without

Commission licensure, but also without the ability to exchange customer data freely with the EDCs. Similarly, §54.36, related to protesting applications should be severely limited or not included in a new application section. Federal law explicitly allows, and in fact, promotes DERA services.

§ 54.39 Reporting requirements should not be carried forward. DERAs' revenues from DER aggregation services will come from the wholesale electricity market. These revenues will not be gross receipts, subject to Pennsylvania's gross receipts tax on retail electricity sales. Similarly, § 54.40 Bonds or other security, should not be applicable to DER service companies because 1) DER service companies' revenues will not be subject to gross receipts taxes; and 2) DER service companies are not providing retail electric service. These are the two purposes stated in the regulations for requiring a bond or other security. Also, in terms of magnitude, it is important to realize that DER revenue is only a small fraction of the total cost of electricity. DER revenue will be generated when a customer forgoes the use of electricity and sells that electricity into the wholesale market. While it is impossible to predict exactly how much electricity consumption any customer may forgo, we know that it will always be just a fraction of total electricity consumed. The wholesale market conditions will drive those sales.

CADRE supports robust consumer protections, including protections against discrimination and predatory marketing practices. However, § 54.43 Standards of conduct and disclosure for licensees should not be carried forward. This section references generation supply and release of information about generation supply. Protections against discrimination and fraudulent marketing are granted to customers under federal and state statutes and regulations as noted in this section. Finally, the mandate to comply with relevant commission regulations and orders could be a condition of licensure. It does not need to be restated here.

IV. Response to Commission's Questions

IV. A. Changes to DER Interconnection Rules

IV. A. 1. Commission Q: Can existing interconnection regulations for customer-generators, 52 Pa. Code §§ 75.31—40, be adapted to address interconnection of a Component DER participating in a DER Aggregation Resource with EDC distribution facilities, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's interconnection regulations that would facilitate this adaption.

There is nothing inherently different about a Component DER interconnecting to the distribution grid with the intent of participating in an aggregation or without that intent. There is no need to test or interconnect entire aggregations, as the aggregations will likely be modified from year to year (or more frequently) to optimize aggregation performance. EDCs generally evaluate interconnection requests under "worst case" scenarios and assumptions. Additionally, EDCs are authorized to evaluate a DERA's participation in the market and they have the right to disallow the DER aggregation's registration with PJM. Requiring a supplemental interconnection review process for aggregated DERs would be unnecessarily burdensome to DER owners, aggregators, the EDCs and likely, the Commission. Such requirements would undoubtedly serve as a barrier to wholesale market participation. If the EDCs have concerns about how aggregated DERs might affect grid voltage, smart inverters are capable of autonomously assisting in voltage regulation in a way that can mitigate such issues.

Once an interconnection is approved (either historically or in the future), there should be no incremental testing or analyses from the EDC to evaluate the resource's fitness for participation in an aggregation. Existing EDC interconnection applications and agreements are sufficiently robust to apply to resources that later join a DER aggregation participating directly in a wholesale market. Interconnection agreements that contain no limitations on system exports signify that the utility has determined that there is sufficient hosting capacity to allow the resource to interconnect with no such restriction. Similarly, if a DER interconnection agreement specifies any export limits, the DER should be required to always adhere to the agreement, regardless of its participation in an aggregation. DERs should not be required to reapply for interconnection to participate in an aggregation – nor should an aggregation of DERs be reassessed for interconnection as a single resource. Either assessment would be redundant to the review that already occurred when the DER initially interconnected.

However, EDC interconnection practices more broadly must be updated to reflect the rise in DER adoption among customer generators – both in terms of the process the customer generator must endure and the cost that it must incur.

Updates to interconnection processes. The EDCs currently have inconsistent interconnection practices and timelines. We urge the Commission to streamline and standardize the interconnection process across all EDCs. The Commission should require EDCs to provide automated platforms for interconnection requests that include built-in application error checking, options for e-signatures, options for electronic payment, online scheduling for inspections or remote inspections, online updates on application status, and online notice that the resource owner has permission to operate ("PTO"). The Commission should also require that PTO timelines be capped (for example, 30 days after date of application). For residential interconnections, if the EDC fails to respond within the set period, the customer seeking interconnection should be deemed to have PTO.

In addition, EDCs should be required to refund customers or pay fines – not recoverable from ratepayers – to the Commission for failing to meet interconnection timeline requirements. These fines could be distributed by the Commission to affected customers or to support other need-based customers. Colorado has recently implemented a policy to refund customers up to 100% of the cost of the interconnection application if the utility does not meet stated timelines. The methodology for the refund calculation is a two-step process:

> First, the Company shall begin calculating refunds owed to interconnection customers immediately after the total allowed time for processing an interconnection application. The rate for the refunds is four percent of the application fee, adding on a daily basis. Applying this methodology, for Level 1 applications, the Company will owe interconnection customers a 20 percent refund after five business days of delay beyond the total allowed time for the application, leading to a full refund of the entire application fee after 25 business days of interconnection delay beyond the total allowed time for the application. The refund amount is capped at 100 percent of the original application fee of the customer. However, consistent with Hearing Exhibit 104 and for administrative efficiency, the Company will not provide any refunds that are for less than $25. [20]

The second part of the calculation is to apply interest at the company's authorized weighted average cost of capital. Interest accrues if the company fails to the meet the stated timelines and accrues back to day 1 of the application process.[21]

Finally, the EDCs should be required to post hosting capacity maps showing where interconnection is readily available without an upgrade. These maps are not available today in Pennsylvania, but they are available in other neighboring states including New Jersey, Maryland,

[20] Unanimous Comprehensive Settlement Agreement, In the Matter of Advice Letter No. 1921 Electric Filed by Public Service Company of Colorado PUC No. 8-Electric Tariff to Implement Its Interconnection Tariff Effective July 31, 2023, Public Utilities Commission of the State of Colorado, Proceeding No. 23AL-0188E, October 26, 2023, pp. 3-4.

[21] Id. p. 4.

Delaware and New York.[22] Once implemented, these maps should be updated on a routine basis, and over time, updated to immediately reflect changes in network conditions.

Updates to interconnection fees. In the ANOPR Order, the Commission cited parts of the Choice Act which could indicate that the customer should be responsible for upgrade costs.[23] For several reasons, we do not believe this section of the Choice Act is relevant to DERs participating in wholesale markets. As discussed above, the Choice Act is not applicable to DERs generally. The Choice Act facilitated one-way delivery of competitive energy services to be sold at retail. So while the Choice Act absolved EDCs from any "obligation to install nonstandard facilities, either as to type or location, for the purpose of receiving energy from the energy supplier unless the energy supplier or its customer pays the full cost of these facilities,"[24] that provision clearly applies to instances in which wholesale energy being delivered from *outside* of the EDC territory to the EDC territory for delivery to retail customers. DER aggregations do just the opposite – they aggregate energy from *within* the zone to deliver outside the zone, to the wholesale market.

Given that the Choice Act is inapplicable, the Commission must determine a fair method for allocating the costs of interconnections. In doing so, it must recognize both the evolving nature of the electric distribution grid and the role the EDCs play in maintaining it. The grid is quickly changing. Electricity demand growth is expected to reach unprecedented levels over the next several years. Therefore, the need for tools to manage that growth is also growing. One of

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[22] See: https://www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps. Some of these states' maps are limited to EVs, storage or other resources.
[23] ANOPR Order, p. 13, citing 66 Pa. C.S. § 2807 (a) [sic].
[24] 66 Pa. C.S. § 2807 (b).

those tools, bi-directional flow of electrons back to the wholesale market, is the topic of this rulemaking. This ANOPR order explicitly recognizes the changes and the need to address the changes. The expansion of bi-directional flow on the distribution grid benefits all customers with lower costs and increased reliability. The utilities are regulated monopolies. They have the privilege of operating in a competition-free environment and are guaranteed a rate of return on their investments. In return, they must manage the grid to meet the needs of their customer base – however those needs evolve.

Today, the utilities evaluate resources individually and assess the engineering needs to interconnect each individual customer using methodologies that are opaque to the interconnecting customers. This results in customers paying wildly different costs for interconnecting, and the support for the costs is not transparent. The current approach also has the potential to create significant first mover disadvantages as the first mover might have to pay a six-figure interconnection cost, but then the property next door can interconnect a resource for practically nothing.

CADRE is aware of at least two cost models which could modify this and be fairer to all customers. First, the EDC could rate base the entire cost of interconnection. This model recognizes that DERs provide a value to the grid generally and that EDCs have a responsibility for upgrading the "poles and wires" to adapt to customer needs and preferences. This model also recognizes that the EDCs, as regulated monopolies, have an obligation to meet the needs of customers as their demands on the electricity grid evolve. The fundamentals of the electricity grid are changing. EDCs around the country are upgrading grid infrastructure to accommodate "electrification" load growth, data center load growth, EV charging and bidirectional flow of electricity on the grid. The use of the electric grid is changing, arguably to the betterment of all consumers. These upgrades are needed for grid reliability and resilience. DER participating in wholesale energy markets should be viewed as a byproduct or benefit of these improvements, not the cause of the improvements. The grid should not be improved on a "customer by customer" basis.

CADRE could also support a tariff-based, fixed fee model to interconnect to the distribution grid, where interconnecting customers pay a modest fee based on the size of the interconnecting resource. It could be a $/kW assessment or a hybrid flat fee plus a $/kW charge. The fees could vary between EDCs and differ for different technologies. We believe it is important for clarity and market efficiency that the fees be reasonable, pre-defined, fixed, tariff-based and competitively neutral.

With a fixed-cost interconnection model, developers and customers could assess their costs of developing DER before expending internal and EDC resources on interconnection studies. Under the current cost recovery model, initial analyses are performed before the EDC studies are performed. These analyses must be refined after the EDC assessment is performed, perhaps only to find out the upgrade costs make the project infeasible. The current approach wastes the resources of the customer, the DER provider, and the EDC.

The fixed-fee cost allocation model would eliminate the vast differences in interconnection costs for similar resources behind the same EDC. It will streamline the interconnection process. It could become a funding model for distribution upgrades required to support deployment of DER. It would be a direct funding model from DER participants. It will not likely match every participant's exact cost to interconnect. However, it could be designed to be a fair price, competitively neutral, pre-determined and tariff-based so that customers have some certainty about moving forward with a DER investment. To be clear, CADRE is not proposing a fixed fee for interconnection applications, as currently exists in the Commonwealth. We are proposing a tariff-based assessment for the physical interconnection. If costs are to be borne by interconnecting customers, CADRE supports a flat fee model.

CADRE is not recommending a particular rate or cost to interconnect in this docket. The rates for interconnections would be determined at a later date. The costs would need to be determined in a transparent stakeholder process, similar to a rate case. We urge the Commission to determine these costs in a "sole-issue" proceeding, not a proceeding bundled together with many other issues. Once each EDCs' interconnection rates are determined, they would be published in the respective tariffs.

In each of these models, some distribution upgrade costs will be socialized among all customers on the grid, each of whom will benefit from the increased deployment of DERs. These models will avoid charging prohibitive fees to a single customer for upgrades that are, arguably, the responsibility of the EDC as the owner and operator of the distribution system and not the interconnecting customer.

CADRE addresses Equity issues in Section IV. O. 1, below. However, we thought it important to share an environmental justice interconnection practice from another state in this interconnection section. The Commission could emulate Connecticut and provide consideration for environmental justice communities in this process. The Connecticut Public Utility Regulatory Authority ("PURA") has adopted a flat fee for interconnecting customers to pay, except for those that live in qualified environmental justice communities. The PURA decided that instead of having residential interconnecting customers that require a new or modified distribution transformer paying the cost of the transformer upgrade upfront, that two different approaches will be used to cover the cost of upgrades. PURA ruled that:

Instead, two approaches will be used to cover the cost of distribution transformer upgrades depending on whether the applicant meets the Environmental Justice (EJ) eligibility requirements outlined below:

1) For applicants meeting the EJ eligibility requirements (EJ applicants), the cost of upgrading the distribution transformer will be recovered by the EDCs across all ratepayers through their next rate case proceeding.
2) For applicants not meeting the EJ requirement (non-EJ applicants), the EDCs will offset a portion, and ideally all, of the costs of non-EJ distribution transformer upgrades through an adder charged to all non-EJ applicants as part of the interconnection application fee. Any remaining transformer upgrade costs will be recovered by the EDCs across all ratepayers through their next rate case proceeding."[25]

CADRE Recommendation: If the Commission believes that interconnection customers should pay for interconnection costs, CADRE recommends that 52 Pa. Code § 75.33 be modified to read: "The Commission will determine the appropriate interconnection application fees and implementation costs for Levels 1, 2, 3 and 4. Such costs will be fixed and be published in each EDC's tariff. In circumstances when standard forms are used for the interconnection process, examples of those forms shall be posted on the EDCs' websites." (Redlines indicate added language.)

IV. A. 2. Commission Q: How will Component DERs previously not subjected to interconnection (energy efficiency and demand response resources) be integrated into an aggregation?

EE and DR currently participate in wholesale markets as capacity, energy and/or ancillary service resources. These products do not inject energy to the grid, rather, they avoid the receipt of electricity at the meter. PJM has defined rules of participation for homogeneous and

[25] Decision, Connecticut Public Utilities Regulatory Authority, *PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation*, Docket No. 22-06-29, December 20, 2023, pp. 12-13. Decision can be found at: 220629-122023.pdf (state.ct.us)

heterogeneous aggregations that include EE and DR components. These rules include the notification to the applicable EDC of the customers' participation in the market. CADRE does not envision the need for the Commission to address anything specific in its new regulatory model to facilitate the integration of a load resource with an interconnected resource.

IV. A. 3. Commission Q: In consideration of future technology advancement through distributed energy resource management systems (DERMS) and other technologies that may allow for utility direct control and overrides, should approval of interconnection requests extend to consideration of an option for firm and non-firm approval categories to reduce the need for system upgrades?

CADRE believes that the EDC should not have direct control over a DER or DER aggregations participating in wholesale electricity markets. FERC has given the EDCs a significant amount of authority in its Order No. 2222. Notably, FERC allows the EDCs to override a PJM dispatch of DERs and DER aggregations[26] in circumstances where such an override is needed to maintain the reliability and safe operation of the distribution system.[27] EDC overrides of a DER dispatch should only be ordered in the case of a reliability emergency that would be caused by the dispatch. In every instance of an override, the EDC should communicate directly to PJM, the DERA, and the Commission. We believe the Commission should be apprised in real-time of any potential threat to the distribution grid and that is what is required to trigger an EDC override of a PJM dispatch order. Action is required from the Commission to ensure data flow occurs between EDCs and DERAs, particularly when it comes to the EDC overriding a DER dispatch.

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[26] Order No. 2222, ¶ 310.
[27] Order No. 2222, Para 310.

CADRE suggests in Section IV. L. 1 that the EDCs should implement retail DER programs to address distribution system needs. These programs could be designed to support non-wires distribution investment alternatives, demand management programs, EV programs or other initiatives. It is conceivable that in those programs, under certain contract conditions, the EDCs would want or need to have device-level controls. These comments are not intended to prohibit such arrangements at the retail level.

Order No. 2222 also requires communication between the EDC and the DERA in cases of an outage on the distribution system – either planned or unexpected. As PJM does not regulate the EDCs, PJM cannot require or specify information flow from the EDCs to DER Service Providers. These requirements must come from the Commission. CADRE suggests that the Commission be prepared to work with the EDCs and DERAs, with representatives from customers hosting the DER, to determine the requirements for information that will be shared and processes to do so. At a minimum, the Commission should define: 1) clear criteria that define reliable and safe operations and justify an EDC override; 2) procedures for advance notification of an outage to DERAs and DER owners/operators; and 3) after the fact justification review.

CADRE does not support the use of nomenclature to distinguish a "firm" and "non-firm" approval categories. The Commission did not clarify what is meant or what would be the difference between the two categories of resources. PJM's capacity resources, including DER and DER Aggregations are contractually obligated to be "firm" and are penalized if they are not available when called. Additionally, the EDC will review each interconnecting asset and assess its impact on the distribution network.

CADRE is also concerned about the Commission's use of this distinction to "reduce the need for system upgrades," as indicated in the Commission's question above. The distribution network will need to be upgraded to accommodate a rapidly changing electricity market. If the market reveals that a distribution upgrade is needed, the upgrade should be made. The EDCs should not be allowed to effectively punish a DER or DER Aggregation because the distribution system is inadequate to accommodate a modernized electricity market. The EDCs should be incentivized to upgrade the distribution network to have non-firm resources classified as firm. The active and unconstrained participation of DER will ultimately reduce energy and capacity costs for all customers. Those benefits should more than outweigh the distribution cost increases.

CADRE Recommendation: Add new Sections 78.10 through 78.15 to Title 52 of the Pa. Code in a Dispatch Management Subchapter that will regulate the EDCs ability to override a dispatch signal from PJM.

- **§ 73.10 EDC dispatch override responsibilities. EDCs may only override a DER dispatch signal from PJM when the reliability of distribution system would be jeopardized by such dispatch. If a reliability issue is known in advance of PJM's schedule or dispatch order, the EDC must provide the DER aggregator and the Commission with advance notice such reliability issue and override.**
- **§ 73.11 DER Service Provider Obligation. DER Aggregators must adhere to an EDC override order.**
- **73.12 EDC Override procedures. EDCs should use best efforts to inform DER Aggregators of a potential override at least one hour before the RTO/ISO day-ahead offer period closes. If system conditions change such that the reliability concerns abate, EDCs should notify DER Aggregators before the close of the real-time bidding window that system conditions will allow safe dispatch.**
- **§ 73.13 Override mitigation. If a PJM dispatch order is overridden by an EDC, the EDC must:**

- **(a) within one (1) calendar day, communicate the reason for the override to all DER Aggregators licensed in the EDC territory and to the Commission;**
- **(b) within 60 days of the override, develop a plan to mitigate any future similar overrides, and within 180 days, complete any system changes identified in the plan, including distribution system upgrades, if required.**

- **§ 73.14 EDC Error. If an EDC issues an override order that prevented a DER or DERA that received a scheduling instruction from the RTO/ISO from being dispatched, and the EDC cannot show that the reliability of the distribution system would have been compromised by the dispatch, or does not take action within 180 days to mitigate future overrides, the EDC will be liable to the DER Aggregator for any direct costs assessed to the aggregator by the RTO/ISO as a result of the override or future similar overrides. These costs shall not be recoverable from EDC ratepayers.**
- **§ 73.15 EDC Communication. EDCs must communicate planned and unplanned distribution system outage to DER Aggregators with customers in the affected outage areas. Planned outages must be communicated at least 48 hours in advance of the outage, or if the planned outage is planned less than 48 hours in advance, as soon as reasonably possible. Unplanned outages shall be communicated immediately to each DERA licensed and operating in the EDC's service territory.**

IV. A. 4. Commission Q: Under what conditions will direct control vs. monitoring be required?

Direct control is a model that can and will be used by DERAs to manage some electrical devices. These control technologies are already deployed today to manage thermostats, pool pumps, hot water heaters and other devices. However, this control is based on a contractual relationship between an aggregator and a customer. Under no circumstance should the EDC have direct control over a DER participating in wholesale electricity markets. As noted above, the EDCs can communicate dispatch overrides to the aggregators (and PJM and the Commission). The aggregators will be bound by those instructions. Deviations from those instructions could result in penalties from the Commission.

“Monitoring” is somewhat a vague term. Under FERC Order No. 2222, the EDCs have certain rights and obligations, some of which are related to maintaining a reliable distribution network. Monitoring of behaviors on the network is part and parcel to maintaining a reliable network. If this question relates to active monitoring of customers’ behaviors for compliance purposes during a PJM dispatch, we believe that is outside the scope of EDC responsibilities. The EDCs should not be granted “monitoring” authority over any resource or resource aggregation for compliance purposes. Individual resource compliance will be governed by the contract between the DERA and the customer.

IV. A. 5. Commission Q: How should the DER aggregation review process differ for different use cases, market services, DER compositions or grid conditions?

The use cases for DER and DER aggregations, from the perspective of this rulemaking, are wholesale market use cases. CADRE has proposed that the DER and DER aggregations assembled to provide services to the wholesale market could also provide distribution level services. Because the use cases are wholesale, we do not believe the aggregation review process should differ at all. We also believe that the study of different wholesale use cases is outside the bounds of Commission jurisdiction. Alternatively, if the Commission were to adopt distribution-level programs to capitalize on the flexible assets being developed for the wholesale market, the review process for different use cases might be different.

CADRE believes that generally, an aggregation of DERs should be viewed no differently than a single DER. If an EDC accepts a resource for interconnection, it has to assume that the newly interconnected resource will respond to signals when other resources respond. For example, rooftop solar resources are likely to inject power back to the grid in the middle of the day and not inject power at night, regardless of a PJM price signal. In contrast, storage resources are likely to dispatch in response to price signals. Each DER aggregation will be developed to maximize the value of the aggregation to the customers and to the aggregators. The Component DERs that comprise capacity aggregations will likely change from year to year. Energy and ancillary service aggregations, to the extent they are separate from the capacity aggregations, will likely change more frequently, especially as the market is growing.

IV. A. 6. Commission Q: How should load assumptions be adjusted to accommodate the use of load-modifying resources?

As DER market penetration expands, load forecasting for distribution system needs will likely be different than for assessing generation needs. For generation forecasting, which is generally managed at the federal level by PJM, there is nothing fundamentally different with DER aggregations than with demand response aggregations. Capacity resources are the only true load-modifying resources. Capacity resources are contractually obligated to "perform" when dispatched by PJM and the Component DER in each aggregation will have must-offer energy requirements if they are capacity resources. Resources providing only energy and/or ancillary service resources are economic resources and will be dispatched only according to the appropriate economic signal from PJM. PJM considers all of these resources and their respective obligations in its planning process.

CADRE understands that from a distribution planning perspective, forecasting for distribution investment needs might be something other than traditional "load" forecasting. It is possible that with a robust DER market, certain measures of load might decrease. At the same time, distribution investment needs might increase. Instead of a peak- or other -load centric metric, the appropriate measure might move to a "flow-based" calculation. The total electron flow might be more important than peak loads. We encourage the Commission to accept changes in distribution forecasting approaches if needed.

IV. A. 7. Commission Q: What data will DERAs need to provide to EDCs and to what extent can this leverage existing PJM registration data requirements? How should these data be documented?

PJM registration requirements are quite extensive. PJM's proposed Tariff, Section 1.4B PJM details more than a page of registration requirements which are shared with the EDC. PJM describes the requirements as criteria "by which the distribution utility can determine: (1) whether each proposed Component DER is capable of participation in a DER aggregation, and (2) that the participation of each proposed Component DER in a DER Aggregation will not pose significant risks to the reliable and safe operation of the distribution system." The tariff also provides the EDC with avenues to seek more information if needed. If the EDCs feel that they need additional data, CADRE encourages the EDCs to work directly with PJM to modify their data requirements. It is an unnecessary and wasteful use of resources to have PJM data requirements that differ from the EDC requirements. We encourage the Commission to not add to the data burden by creating additional requirements through this rulemaking process, especially given the nascency of this DER market. If additional data requirements develop over time, they can be addressed, but are best addressed through the PJM tariff or other avenue, rather than formal regulations.

IV. A. 8. Commission Q: Where should automation versus manual coordination and communication between EDCs, the DERA and PJM be required?

Similar to data requirements, PJM has established communication and telemetry protocols that are designed to ensure timely communications regarding DER and DERA performance. The communication relationships should be limited to being between the DERA, PJM and the EDC. The Commission should require the EDCs to automate certain communications. For example, planned distribution network outages and override communications should be fully automated and licensed DERAs should have access to those systems. Beyond requiring automation for communicating core issues, we encourage the Commission to not mandate further communications requirements, especially at this early stage of DER market development.

IV. A. 9. Commission Q: How should the PUC ensure that the EDC DER registration approval process is efficient to consistently meet PJM's 60-day timeline and avoid potential "over-registration"?

PJM has established a fairly comprehensive pre-registration and registration process. These processes have been approved by FERC and will ultimately be included in the PJM tariff, Operating Agreement and addressed in PJM Manuals. Instead of adding another layer of regulation, that might slow the EDC review process, the Commission should consider a "carrot or stick" mechanism to incentivize timely reviews and approvals. Ultimately, the EDCs should be encouraged to facilitate DER growth. That will lead to the best outcome for customers. To the extent that the EDCs are not meeting their obligations, the Commission should entertain a streamlined dispute resolution process.

IV. A. 10. Commission Q: How should the PUC clarify and harmonize the relationship between DER interconnection under PUC regulations with DER interconnection under to [SIC] PJM's small generator interconnection rules, if needed?

Under FERC's definition of distributed resources, a DER is interconnected at the distribution level. CADRE encourages the Commission to focus on streamlining the EDC interconnection process. Efficient and timely EDC interconnection processes will best benefit Pennsylvania customers.

In its ANOPR Order, the Commission cited a PJM tariff provision related to this issue. The Commission noted, "A Component DER interconnecting to distribution facilities for purposes of participating in PJM markets exclusively through the DAPM are not subject to the parts of PJM's tariff relating to interconnections with the transmission system and shall exclusively interconnect to distribution facilities pursuant to applicable state laws and PUC regulations."[28] We therefore encourage the Commission to limit interconnection reviews to distribution level requirements. The review process should not be allowed to consider upgrades to FERC-jurisdictional facilities. If a DER interconnection requires upgrades or changes to the transmission assets, it is likely that the transmission assets or the distribution assets immediately connected to the transmission system are insufficient. These transmission upgrades will likely be required to facilitate the growth of electrification and the modernization of the distribution system that is looming regardless of DERs. These "second level" upstream investments, if required, should be borne by all ratepayers, not the interconnecting customer.

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[28] ANOPR Order, p. 12, citing PJM tariff related to DER § 1.4B(k).

IV. B. Changes to Metering Requirements

IV. B. 1. Commission Q: Can existing metering regulations for customer-generators, 52 Pa. Code § 75.14 (relating to meters and metering), be adapted to facilitate provision of metering and telemetry data by DERAs to public utilities, consistent with Order 2222 and PJM's DAPM, and if so, whether and what specific changes to the PUC's interconnection [SIC] regulations that facilitate this adaption.

This question and the specific regulation cited relate specifically to net metering customers and metering, yet seeks information related to changes to interconnection regulations. CADRE assumes the Commission's intent is to seek information related to metering regulations and we answer accordingly.

The issues of metering, billing and EDI are all related, and effective regulations in these areas are important factors for the successful deployment of DER. CADRE urges the Commission to address these issues in a complementary manner.

52 Pa Code § 75.14 is related to meters and metering specifically for net metered locations. CADRE believes that the current metering regulations are sufficient to measure the inflow and outflow of the net metered resource but are not sufficient to allow wholesale market participation from the net metered resource or from other resources co-located behind the same meter as the net metered resource. The Commission should require the EDCs to accept and process device-level meters and device-level meter data. This is discussed in greater detail in Sections IV. B. 3 and IV. G. 1 below.

The simple bi-directional meter owned by the utility will not capture each of the activities at a DER resource location, rather, it only captures the net inflow and outflow through the primary meter over a period of time. In a market that includes DER participation in wholesale markets, that is not sufficient to provide a robust bill to the customer. For example, the EDC meter will not capture storage to premise consumption, or EV charging curtailment that results in a diversion of solar generation from the car battery to the oven in the kitchen to avoid the use of system power. The premise meter will not capture any of these "behind the meter" transactions that provide immense value to a consumer. The utility meter just captures the net system power consumed at the premise. Device level metering is the tool that will provide the information to generate a robust and truly informational bill to the customer and will also allow DER co-located with NEM resources to participate in wholesale electricity markets.

The DERAs and EGSs are already capable of capturing this data. The importance of the EDCs capabilities are to allow certain resources to participate in the wholesale market. As noted elsewhere, PJM has proposed (but FERC has not yet accepted) the premise that any DER co-located with a NEM resource behind a NEM meter, not be allowed to participate in the energy or capacity markets. PJM has taken the position that this would lead to double counting. With device-level metering, co-located resources could participate in the wholesale electric markets. For example, a storage resource co-located with a solar NEM unit could be dispatched in a system emergency as a capacity resource if the utilities would accept device-level metering.

Under FERC Order No. 2222, it is the decision of the EDC (and therefore ultimately the Commission) to determine what resources constitute double counting. If an EDC only looks at the premise meter, it will not be able to determine if the storage resource was discharged, or if excess solar was generated during the system emergency. However, if device level metering was ordered by the Commission, the EDCs could confirm to PJM that it was an independent resource, not the NEM resource, that responded to the dispatch order.

CADRE Recommendation: See Section IV. B. 3, below.

IV. B. 2. Commission Q: How should interconnection [SIC] regulations evolve to ensure alignment between EDC and PJM telemetry and metering to facilitate consistency and avoid extensive telemetry differences between DERA requirements and retail DERs?

This question relates to metering, yet seeks information related to changes to interconnection regulations. CADRE assumes the Commission's intent is to seek information related to metering regulations and we answer accordingly.

PJM has established telemetry and metering requirements. We encourage the Commission to not impose any further requirements at this early stage of DER market development.

IV. B. 3. Commission Q: Should the PUC facilitate device-level metering and if so, how?

Yes. Device-level metering is required to obtain optimal performance from DER and DER Aggregations, specifically those Component DER resources co-located behind a net energy meter. Under PJM's proposals in its Order No. 2222 compliance docket, all component DER that are located behind the meter at the NEM property, including storage and other potential demand response assets in its resource prohibition are included in PJM's prohibition against double compensation.[29] FERC has not yet ruled on this prohibition. Specifically, FERC has accepted PJM's metering requirements, which do not require device-level metering, but in doing so, FERC has encouraged PJM to work with stakeholders to develop device-level metering

[29] *Id.*, pp. 29, 39. See also: Second Compliance filing of PJM Interconnection L.L.C., Docket No. ER22-962. September 1, 2023, p. 16 ("PJM Second Compliance Filing").

solutions.[30] One of the constraints for device-level metering is the EDCs' inability to process device-level metering data.[31] The Commission should compel the EDCs to establish systems that can accept and process device-level metering data in a manner that will provide DERAs and PJM with requisite data to support Component DER located behind NEM meters to participated in PJM's electricity markets to the extent possible without violating any restrictions on double compensation.

PJM's double compensation rules restrict non-NEM DER co-located with NEM DER behind the utility meter from participating in energy and capacity markets. In order for these resources to participate, PJM has suggested (FERC has not yet ruled on this suggestion) that these customers add an additional utility meter at the premise.[32] If a facility with NEM also has a charged battery, a responsive EV, or controllable load in the form of demand response, those resources, which would be quite capable of relieving a constraint, would not be able to participate in the wholesale market under PJM's proposal. PJM's suggestion of separately metered resources (with separate EDC account numbers) is not viable as it would require individual DER to be on a separate circuit from the NEM resource. That would mean the NEM

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[30] See: FERC Order on Compliance Filing, PJM Interconnection, L.L.C., Docket No. ER22-962-000, ¶ 250. "We find that PJM has demonstrated that its proposed metering requirements do not pose an unnecessary and undue barrier to distributed energy resources, as Order No. 2222 requires, with the narrow exception discussed further above. However, we encourage PJM to continue to work with its stakeholders to consider additional metering options in the future, including for DER Aggregation Resources to utilize device-level meter data."

[31] See: Comments and Request for Second Compliance Filing of the Indicated PJM Utilities Addressing PJM Order No. 2222 Compliance Filing, *"While the EDCs have proposed use of the retail metering point or Point of Interconnection ("POI") to be the point where wholesale market participation is determined, in cases where DER Aggregation impacts the POI meter data or affects retail billing/submetering at a customer location may be needed so as to participate in the wholesale programs. Significant time and expense will be required to facilitate system changes to settle the market and maintain the retail billing processes."* (pp. 27-28) and "*There must be a deliberate approach to metering requirements, which greatly impact EDC operations."* (page 33), FERC Docket No. ER22-962-000, September 1, 2023.

[32] PJM Second Compliance Filing, pp. 18-19.

resource could not directly charge the battery or the EV. Similarly, if the Component DER co-located with the NEM resource were a load reduction resource (air conditioner, pool pumps, other), then it would have to be on a separate meter. It is an incomprehensible outcome for a NEM customer to have air conditioning systems or pool pumps that could not be energized from an on-site NEM resource. Similarly, it does not make sense that a commercial and industrial ("C&I") facility, with significant load participating in demand response, or with large batteries providing backup power, be restricted from participating in the market because a small solar system is located on the property. Universities with multiple buildings and meters, and often with local generation, should be allowed to participate, even if one building has solar. Device-level metering is a tool to alleviate these constraints.

Because the determination of double compensation is left to the EDC, The Commission could resolve this issue by requiring the utilities to accept device level metering and device level metering data. Device level metering is available in most, if not all, modern inverters, storage resources, and EVs and can be implemented on other load management resources quite easily. The Commission should require the EDCs to receive and process device level metering in addition to their current meter reading functions. If the EDCs processed device-level meter data, PJM could validate a resource's contribution to the grid, outside of the NEM component resource. Alternatively, the Commission could define criteria to approve device level meters for revenue-grade and settlement purposes and the aggregators can supply device level data directly to PJM. PJM can process device level data and will accept device level data for certain demand response products. In either scenario, leadership from the Commission will be required to enhance current practices.

To be clear, the Commission should not require device level metering for all Component DERs. That would be inappropriate as many DERs are singular resources located behind a single meter (e.g., controllable thermostats) and meter data from the EDC's existing meters is adequate to provide accurate measurement and verification of DER dispatch. The Commission should require the EDCs to accept and process device-level metering and meter data.

CADRE Recommendation: Add new §§ 78.40 through 78.42 to Title 52 of the Pa. Code related to metering requirements.

- **§ 78.40 Definitions**
    - **Device-level meter – a meter, either internal or external to a specific distributed energy resource, capable of measuring electric consumption and/or injections to the electric grid.**
- **§ 78.41 EDC Metering Requirements. Within 180 days of the issuance of this regulation, each EDC shall develop and deploy meter data systems that are capable of receiving data from device-level meters and processing that data so that it can be used for settlement purposes at the RTO/ISO. In the alternative, the EDCs will work with the RTO/ISO to ensure that a Distributed Energy Resource service provider may supply device-level data directly to the RTO/ISO for settlement purposes.**
- **§ 78.42 Device-level meter technical standards. A qualified device-level meter shall conform to 52 Pa. Code §§ 57.20 -- 57.25 (relating to meter testing) and the American National Standards Institute Standard C12, as applicable, or as these standards may be updated.**

IV. C. Cost Allocation Issues for Facilities Allowing the Interconnection of DERs.

IV. C. 1. Commission Q: Can existing interconnection cost allocation regulations for customer-generators, 52 Pa. Code § 75.36(8), 75.38(e) and 75.39(e)(4) (relating to additional general requirements, level 2 interconnection review, level 3 interconnection review), be adapted to address interconnection cost allocation among Component DERs, DERAs and EDCs, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's interconnection regulations that would facilitate this adaption.

CADRE strongly encourages the Commission to consider either a fully socialized or a fixed-price interconnection model for all interconnection costs, each of which were described in these comments in Section IV. A. 1, above. As noted, electric grids across the country and in Pennsylvania need to be upgraded to support the significant expected load growth from electrification, EVs, centralized EV charging stations, and data centers.

The advent of Order No. 2222 allows interconnecting DERs to provide more valuable grid service to all customers, including enhanced reliability, resilience and decreased costs. Prior to Order 2222, DERs were able to support demand response, but they were limited to operating at a level no greater than the customer's then-current load. They could not inject power to the grid. Demand response has lowered capacity costs by literally billions of dollars over the past 10 years.[33] DER will provide more of the same. With DER injections to the grid, DERs will drive clearing prices in the market down and they will provide a reliability resource for the grid operator. As DERs proliferate, more and more customer facilities will remain operational during grid emergencies. This resilience effect will allow for community warming/cooling centers, electronics and communication charging, food preservation and many other benefits and allow for faster recovery from the grid emergency.

The current "customer-by-customer" cost recovery model for interconnections is outdated and not consistent with either the needs of the distribution system or the evolution of electricity markets and inconstant with the value stream they will produce for all customers. We encourage the Commission to consider these two alternative cost recovery options, select one that will facilitate DER deployment and revise 52 Pa. Code §§ 75.36(8), 75.38(e) and 75.39(e)(4) as appropriate and consistent with the chosen cost recovery methodology.

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[33] See the PJM Independent Market Monitor's annual analyses of PJMs Base Residual Auction at: https://www.monitoringanalytics.com/reports/Reports/2023.shtml

IV. C. 2. Commission Q: How will DERA market participation impact retail rates?

Setting retail rates is a complex process requiring the careful consideration of several components not readily available to non-EDC stakeholders outside of the formal ratemaking process. However, CADRE expects DER Aggregation market participation to generally decrease costs for both participating and non-participating customers. Impacts on the distribution portion of a customer's bill will depend on several matters outside the scope or control of the CADRE Coalition, such as distribution investments made to support EV charging, electrification or data center load growth. It is possible that the DERs will require increased investment in distribution networks. It is equally possible that DERs could reduce or defer the need for distribution investments (further discussion below in Section IV. L. 1, below). Ultimately, decisions made by the Commission in this, or other regulatory processes will determine the overall impact to the distribution network.

It is almost a certainty that on the electricity side of the retail rate, costs will decrease. The two largest components of energy costs are capacity and electrons (or energy). We have seen demand response participation in wholesale markets reduce capacity costs significantly. The PJM Independent Market Monitor has stated numerous times in his annual analysis of PJM's capacity auction that in the absence of demand response participation in the capacity market, capacity prices would be billions of dollars higher than the actual clearing prices.[34] We also know that because of the rules developed in FERC Order No. 745, if demand response participates in energy markets, it must pass a net benefits test, so by its very existence, demand

[34] See the Market Monitor's annual analyses of PJMs Base Residual Auction at: https://www.monitoringanalytics.com/reports/Reports/2023.shtml.

response must lower energy clearing prices if it is cleared in the energy market[35]. While FERC Order No. 2222 does not have the same net benefits test language, Order No. 745 language will still be binding on Component DERs that are demand response resources. More importantly, if a Component DER energy injection clears the PJM market process, it will always be a lower cost option than the resource it displaced. DERA participation in wholesale markets will always result in lower prices that will benefit consumers, including non-participating consumers.

IV. C. 3. Commission Q: What cost recovery guidance, if any, is needed by EDCs for investments that may support both transmission and distribution?

CADRE has no opinion or suggestions on the allocation of costs between transmission and distribution.

IV. C. 4. Commission Q: How should EDCs distinguish cost allocation between grid modernization, general DER costs, and DERA-specific costs?

As discussed above, the electric grids across the country, and in Pennsylvania, need to be upgraded. These upgrades will benefit all customers. The traditional cost allocation model assigned most or all the costs to interconnect, even distribution upgrade costs, to the interconnecting customer. Under FERC Order No. 2222, DERs will provide even more significant system benefits including cost reductions and increased reliability. When considering the comprehensive need for distribution upgrades to modernize the aging grid, accommodate load growth and allow for Order No. 2222 market changes, the "interconnecting customer pays

[35] FERC Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187, 18 CFR Part 35, Docket No. RM10-17-000, March 15, 2011.

all upgrade costs" model makes less sense. We urge the Commission to consider other cost allocation alternatives to facilitate DER growth in the Commonwealth.

This specific question adds the concept of a DERA-specific cost, which we interpret to mean a distribution cost incurred due to a specific aggregator or "aggregation" of DER participating in the wholesale electricity market. CADRE does not believe that the application of any such costs to the DER or the Aggregator is reasonable. If a specific aggregation of resources cannot be deployed, yet each Component DER in the aggregation was awarded an interconnection, that would reflect a distribution shortfall and the costs to resolve that issue should be treated as a socialized distribution cost. To look at this differently, the Component DER of this particular aggregation might act the same way outside of participating in this particular aggregation. For example, the same type of resources might be embedded in several smaller aggregations with different providers. If they all dispatched at the same time, the same distribution problem would exist.

IV. C. 5. Commission Q: What cost recovery mechanisms should be used (upfront charges, usage charges, rates)?

To the extent that utilities assess charges to DER for interconnection, for example, under the fixed fee model discussed herein, payment for those charges should be flexible. Currently, some utilities require payment for interconnection costs before the work is done by the utility. PPL's website says "If reinforcements/upgrades are determined to be required for your interconnection, the customer is required to pay a 25% deposit at the time of signing the Notice of Customer Intent (NoCI) and following completion of the interconnection study. The remaining balance must be paid before the start of construction." The practice of requiring residential and small commercial customers to pay for interconnection construction costs before work is begun should be banned by the Commission. It is certainly appropriate to continue to allow for upfront payments for these costs if that is the customer's preferred method of payment. Under the tariffed interconnection cost concept discussed above, the EDCs could easily build interconnection costs into their billing system and recover those interconnection costs over a period of years. Protections, such as signing contracts for interconnection construction costs and termination of service risk would prevent a customer from having the work done but not paying for it.

CADRE Recommendation: The Commission should prohibit the utilities from compelling residential and small commercial customers to pay for interconnection construction costs in advance of the construction project. The Commission should allow a residential or small commercial customer to choose between upfront payments or allowing customers to pay for interconnection construction costs over time, on their electric bill.

IV. C. 6. Commission Q: What is the interplay between the direct procurements aspects of EDCs' default service plans and an EDC's costs to administer DERA participation in wholesale markets, if any?

As an initial matter, the Commission should make a policy declaration that customers receiving default service from their EDC will not in any way have its access to the DER market limited. A limitation on customer access to wholesale electricity markets is likely outside the scope of Commission. More importantly, such a restriction would place needless hurdles in the market, significantly reducing the pace of growth of the market and potentially limiting the DERAs' market entry into Pennsylvania.

CADRE does not see any interplay between the EDCs' procurement of default service and the EDCs' costs to administer DERA participation in wholesale markets. In fact, the different utility functions benefit different categories of customers and in both markets, participating customers provide net benefits to the non-participating customers. The direct procurement of default service only benefits default service customers and shopping customers subsidize costs to serve default service in distribution rates. DERA participation in wholesale markets benefits all customers, even non-participants by driving lower prices and increasing grid reliability. There is no justification for allocating the EDCs' costs to administer DERA participation in wholesale markets to aggregators or DER customers.

IV. D. Adjudication of Disputes Regarding the Registration of DERs

IV. D. 1. Commission Q: Can or should the existing application process for net metering customer-generators, 52 Pa. Code § 75.17, or its existing dispute resolution regulations, 52 Pa. Code Chapters 1 (relating to rules of administrative practice and procedure), 3 (relating to special provisions) and 5 (relating to formal proceedings), or both, be adapted to facilitate adjudication of disputes about DERA registration of its Component DERs with PJM, consistent with Order 2222 and PJM's DAPM, and if so, the specific changes to the PUC's regulations that would facilitate this adaption?

FERC Order No. 2222 requires the RTO/ISOs to include dispute resolution provisions in their tariffs.[36] However, these provisions are limited to issues that fall within the RTO/ISO's tariff. PJM's dispute resolution process will not address issues that PJM determines "solely concern the application of any applicable tariffs, agreements, and operating procedures of the Electric Distribution Company, and/or the rules and regulations of any Relevant Electric Retail Regulatory Authority."[37] To the extent a tariff dispute arises, for example, about the interconnection of a DER, a delay in the registration process or some other "local" matter, the

[36] Order No. 2222, ¶ 292.
[37] PJM Compliance filing. 9-1-23, page 54.

dispute must be resolved at the state level. The Commission should implement a dispute resolution process specifically to address DER/Order No. 2222 issues, especially for disputes concerning application review, interconnection, compensation, and grid reliability issues.

FERC requires the EDCs to review interconnection applications for aggregations within 60 days. FERC requires this timeline because the Component DER in an aggregation have already been through the interconnection process and reviewed by the utilities. The 60-day limit is to review the impact of these assets being aggregated and dispatched. PJM will monitor the applications. However, any complaint by an aggregator, either regarding the timeline or rejection of an application that is perceived to be incorrect, will need to go to the Commission for resolution.

PJM is also unable to verify whether an asset is receiving compensation for a wholesale service in a retail tariff, therefore that responsibility remains with the EDC. Similarly, the Commission should be prepared to adjudicate over disputes between aggregators and EDCs over tariffs and whether assets are or are not compensated for a service in the retail tariff.

In the ANOPR Order, the Commission noted that the EDCs requested that the Commission also consider a dispute resolution process or a complaint process regarding disputed participation decisions.[38] We agree that a streamlined process would serve the customers and EDCs best interest. We also support expansion of the process to include reviews of other issues as well, including issues with double compensation claims, dispatch overrides and others that may develop.

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[38] ANOPR Order, pp. 28-29.

CADRE cannot foretell the full extent of potential disputes between DERAs and the EDCs. We know there will be disputes and we are pleased that the Commission recognizes this dynamic. When a dispute arises, these disputes should not be left to be a matter of EDC discretion. The market will need meaningful Commission oversight on these matters. A streamlined dispute resolution process will provide a useful tool that will enable the Commission to respond to and resolve disputes in a timely and efficient manner.

We envision that when disputes arise, they are likely to be a result of an interpretation of rules rather than disputed facts. Accordingly, most disputes will not rise to the level of a "contested proceeding" at the Commission. The streamlined dispute resolution process should disallow, or allow only in limited cases, data requests, interrogatories, testimony, and other tools typically reserved for use in PUC litigations. Customers will be investing large sums of money in DER. Customers will be looking for rapid resolution of disputes. Needless delays in getting timely resolution on issues of interpretation are a business deterrent and will stifle investments in DER. A disciplined and streamlined dispute resolution process will enhance the DER market and should be implemented by the Commission.

IV. E. Management of Distribution Utility Overrides of DERs to Maintain reliability, and Disputes Arising Therefrom

IV. E. 1. Commission Q: Can or should the regulations be augmented to address EDC overrides of DER Aggregation Resource or Component DER operation, consistent with Order 2222 and PJM's DAPM, and, if so, the specific changes to the PUC's regulations that would address overrides. How?

The Commission should be very concerned with the practice of EDC overrides. CADRE has suggested regulatory language to protect against unwarranted dispatch overrides in Section IV. A. 3, herein.

IV. E. 2. Commission Q: How should the distribution override process align with market bidding windows?

Distribution overrides, to the extent they are ordered, should be ordered before the day-ahead market bidding window closes. The EDCs will have insight into all the DER aggregations in its service territory. If a certain DER (component or aggregation) is known to be a problem by the EDC, this problem should be communicated to the aggregator in advance of any bidding window. That communication should state the express cause of the problem. For example, is it a hot weather issue, a cold weather issue, a specific resource issue, or something else? With this knowledge, an aggregator could manage the aggregation efficiently, either by modifying the components in the aggregation or only offering during "safe" conditions.

Real-time overrides should be avoided at all costs. An override could be very costly for a DERA. In energy markets, if the DER energy is not delivered, the aggregator would be responsible for procuring replacement energy. During a capacity event, the penalties for non-performance can be much more severe. Perhaps even more importantly, PJM will be relying on the DER resources when dispatched. A real-time override that contradicts a PJM capacity instruction could cause, rather than prevent, large-scale reliability issues, potentially bringing harm to wide swaths of customers.

IV. E. 3. Commission Q: What EDC "real-time" update and override requirements should be addressed in DERA agreements to ensure the reliability and safety of the grid?

The gravity of an EDC dispatch override could potentially be quite severe, both financially and from a reliability perspective. PJM dispatches capacity resources like demand response and presumably some other DERs during, or to avoid, transmission-level system emergencies. As a result, real-time overrides should be only used when other measures are not adequate and as a "last resort" solution. We have provided proposed regulations governing EDC dispatch override procedures in Section IV. A. 3, above.

IV. F. Protection Of DER Owners From Unfair Trade Practices Or Excessive Risk In The Wholesale Markets

IV. F. 1. Commission Q: Does the UTPCPL apply to the DERA-Component DER relationship? How can or should the PUC's EGS regulations be adapted to address consumer protection in the DERA-Component DER relationship, consistent with Order 2222 and PJM's DAPM? If so, what specific changes to the PUC's regulations would address these matters.

The Commission is concerned that the Pennsylvania Unfair Trade Practices and Consumer Protection Law ("UTPCPL") might not apply to DERAs because they might not be deemed to be sellers if a DERA "simply aggregates Consumer DERs' available energy for sale in PJM's wholesale market."[39] While not necessary, in all likelihood, DERA will likely be simultaneously buying and selling goods and services to consumers, so the law would apply in many DER relationships. The Commission noted the complexity of a DER transaction that included a "sale" when addressing this specific topic.[40]

Additionally, we have noted above that CADRE is not seeking a "no regulation" market. However, the Commission must be aware of the line between wholesale and retail regulations. Demand response participating in wholesale markets is unequivocally a wholesale service.[41] The Commission does not regulate the relationship between demand response providers operating in the Commonwealth and their customers. There is no reason to believe that DER participation in

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[39] ANOPR Order, p. 33.
[40] ANOPR Order, p. 32.
[41] FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760 (2016).

the wholesale electricity market is or should be any different. DER participation will impact wholesale electricity prices in the same manner that demand response affects wholesale rates.

CADRE understands that the Commission and other stakeholders may be concerned with customer protection and other issues that are seemingly retail in nature but might actually be part of a wholesale (FERC-jurisdictional) transaction. The Commission should understand that willing customer participation is required for successful DER aggregations. As noted above, the customer-aggregator relationship will be tightly aligned. It will not be in an aggregator's interest to take economic advantage of its customers because an unhappy customer can wreak havoc over the DERA participation model. We encourage the Commission to exercise patience to determine if consumer protections are necessary before enacting any incremental consumer protection regulations specifically aimed at the DER market. DER, like demand response, is very customer-focused and tends to reduce costs for participating customers and the market. Overly burdensome consumer protections might interfere with the customer-aggregator relationship to the detriment of all customers, including non-participating customers.

IV. G. Prevention Of Double Compensation Or Double Counting Between Retail And Wholesale Market Participation, Including Rules Governing DER Owners' Ability To Switch Between Retail And Wholesale Market Participation

CADRE does not endorse double compensation; however, we urge the Commission to exercise caution when developing regulations that seek to prevent double compensation. It is important to understand what should be considered double compensation and what is not double compensation. Double compensation arises from being compensated twice <u>for the same service in the same time period</u>. Being compensated for energy, or capacity at wholesale, while also being compensated for those same products for a different retail purpose does not constitute double counting. For example, a DER aggregation could provide capacity to address EDC system conditions and to provide emergency relief during a PJM system emergency. This should not be considered double compensation; such applications may or may not be coincident. They are separate services because the EDC has dispatch authority distinct from PJM operations, which are outside of control of the EDC. Double compensation is a contentious issue, and we seek strong Commission guidance to clarify what is and is not double compensation. We encourage the Commission to look to FERC for guidance on this issue.

FERC has ordered the RTOs to accept registrations from customers participating in one or more retail programs unless the programs compensate for the same service. There are, for example, some utility demand response programs that are directly tied to the RTO demand programs and participation in both would result in double compensation. These are mostly found in the vertically integrated states that opted out of Aggregator Participation in wholesale demand response markets under FERC Order No. 719. Pennsylvania does not operate retail demand response programs that are directly tied to PJM's demand response programs. When the Pennsylvania EDCs deployed demand response under their respective Act 129 programs, customers were compensated for providing load reduction from the from the host utility and many also participated in PJM's wholesale market demand response programs. Different demand management programs serve different purposes. Just like a doctor who can address many different medical problems, DER can address many different electricity concerns. CADRE believes that addressing double compensation appropriately will yield outcomes that will provide win-win solutions, for participants, non-participants, and the EDCs.

IV. G. 1. Commission Q: Can or should existing regulations on compensation for net metering customer-generators, 52 Pa. Code § 75.13, be adapted to incorporate appropriate restrictions on double counting of services provided by a Component DER in wholesale and retail markets, on duplicative compensation for the same service, consistent with Order 2222 and PJM's DAPM, or on both, and, if so, what specific changes to the PUC's regulations would or should facilitate this adaption.

CADRE understands the need for restrictions on double compensation, but believes that PJM's tariff, along with EDC approval of DER participation in aggregations is sufficient oversight to prevent double compensation. We believe that the Commission should enable the use of device-level metering which would facilitate more participation in DER markets, including resources co-located with NEM resources. Specifically, CADRE has concerns about protecting the rights of customers participating in Net Energy Metering ("NEM") programs. We encourage the Commission to review our earlier comments related to this topic, in Section IV. B. 3, above.

While FERC has not issued final rules on all open NEM issues, FERC has ruled that customers should not get paid twice for providing the same service. Order No. 2222 specifically "(1) allow[s] distributed energy resources that participate in one or more retail programs to participate in its wholesale markets; [and] (2) allow[s] distributed energy resources to provide multiple wholesale services." The Order then allows the RTO to "(3) include any appropriate restrictions on the distributed energy resources' participation in RTO/ISO markets through distributed energy resource aggregations, if narrowly designed to avoid counting more than once the services provided by distributed energy resources in RTO/ISO markets."[42] CADRE has no concerns about restricting "double compensation" as FERC has defined it (customers can

[42] Order No. 2222, ¶ 160.

participate in wholesale and retail programs). CADRE believes that "double compensation" must be defined by the Commission in a similar fashion to FERC's definition so that the EDCs can properly determine when a customer might potentially be "double compensated," and at the same time, the Commission should enable device-level metering, which would be the first step toward enabling resources co-located with NEM resources.

PJM has taken the position that NEM customers receiving a retail rate for excess energy production cannot get paid twice, once through the NEM program and then again for participating in energy or capacity markets. PJM has ultimately left the determination of allowing a NEM customer to register in a DER aggregation to the EDC because state and EDC programs are all different[43] with some offering a retail rate for excess generation and others offering something else. In taking its position, PJM has included in its prohibition all Component DER that are located behind the meter at the NEM property, including storage and other potential demand response assets in its resource prohibition.[44]

CADRE believes that there could be state-supported solutions to allow NEM resources to participate in wholesale markets and allowing component DER co-located with a NEM resource to participate in wholesale markets. The Commission should strive to allow early adopters of advanced energy technologies such as NEM participants to continue their journey to more advanced energy management. It seems to be flawed energy and environmental policy to stifle the early movers, who have previously committed to a long-term investment in renewable energy

[43] Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C. and Motion for Extended Comment Period, Docket No. ER22-962, p. 40, February 1, 2022.

[44] *Id*., pp. 29, 39. See also: Second Compliance filing of PJM Interconnection L.L.C., Docket No. ER22-962. September 1, 2023, p. 16 ("PJM Second Compliance Filing").

resources, from advancing the energy markets further. To be clear, NEM resources should not be moved in their entirety to the wholesale market. That would undo a regulatory promise made to those customers who invested in NEM resources. However, they should be allowed – even incentivized – to continue their market leadership by participating in wholesale electricity markets.

NEM resources are valuable resources for which Pennsylvania NEM participants have invested substantial sums of money. Modernizing the NEM programs to meet the needs of a more modern electricity market will further enable these customers to contribute to the grid, while reducing costs of energy and of the NEM programs which will benefit all customers. In contrast, maintaining the status quo for NEM customers, specifically, preventing other Component DER from participating in the wholesale electricity market, locks those customers in place, providing no incremental system benefit, leaving a valuable resource significantly under-utilized.

CADRE Recommendation: 52 PA Code § 75.13 should be modified to add section (m) that states: "Nothing in this subchapter prevents a Net Metered resource, or other distributed resources co-located at a net metered premise, from participating in wholesale energy market programs, provided the resources are not compensated two or more times for providing the same service."

IV. G. 2. Commission Q: Does the PUC have authority to decide whether to permit net metering customers to participate in DERAs, noting FERC's statement that "under a [RERRA]'s jurisdiction over its retail programs, such a [RERRA] is able to condition a distributed energy resource's participation in a retail distributed energy resource program on that resource not also participating in the RTO/ISO markets"?

CADRE does not have an opinion on whether the Commission has this authority. However, CADRE believes that in Pennsylvania, such a decision would amount to bad policy. Prohibiting, or even limiting, a net metering customer's ability to participate in wholesale electricity markets would constrain the early adopters from expanding their role in the electricity markets. The Commission should be encouraging the opposite. Customers should be fully engaged in the energy market to the extent that they are capable and without receiving compensation multiple times for the same services. An EDC can prevent a DER from participating in wholesale markets if that would result in double compensation. The Commission does not need to issue a regulation to give this authority to the EDC. A broad or poorly designed regulatory ban prohibiting net metering customers from participating in wholesale markets will almost certainly lead to unintended bad consequences and the Commission should avoid that as this market is developing.

IV. G. 3. Commission Q: Assuming the PUC does have requisite authority, should the PUC permit net metering customers to also participate in DERAs at the same time?

CADRE believes the answer here is an unequivocal "yes" to the extent possible, and subject to the prohibition on double compensation. Because this market is still developing, the Commission should refrain from issuing regulations regarding the ability or inability of net metered resources from participating in wholesale electric markets. Again, to be clear, we are not seeking, and in fact are opposed to any effort to move NEM customers to the wholesale market. This would undo a long-standing regulatory practice and would be in direct conflict with Pennsylvania's AEPS Act.[45] See discussion above.

IV. G. 4. Commission Q: Assuming the PUC does have requisite authority, should the PUC develop rules for when and how often a retail customer may switch between net [SIC] metering and DERA participation?

No. The Commission should consider the extent to which it would like to see net metered customers participate in the wholesale electricity markets and provide more options for that participation. CADRE does not believe that a customer is likely to switch between net metering and DERA wholesale market participation. Customers are more likely to expand their resource portfolio and participate incrementally as a Component DER. For example, a solar customer might add a storage resource to its energy portfolio if that storage device can get compensated for providing incremental capacity and ancillary services to the grid. The Commission should focus on incremental opportunities for customers, not limiting customers' options. Device-level metering will be required to facilitate incremental opportunities for net metered customers. We have addressed device-level metering in Section IV. B. 3, above.

[45] The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213, (AEPS Act), November 30, 2004. 73 P.S. §§ 1648.1 *et seq*.

IV. H. Any Necessary Electronic Data Exchange Revisions

IV. H. 1. Commission Q: Should the PUC encourage or impose EDI and/or other data exchange protocols between and among EDCs, EGSs, DERAs and Component DERs to facilitate implementation of Order 2222, and, if so, what, if any, specific changes to the PUC's policies and regulations would or should facilitate this adaption.

The CPower/Enerwise matter discussed above is clear evidence that DERAs need access to customer data to facilitate a robust DER market. Also, the Pennsylvania statutes expressly allow third party access to Customer Data: "(3) Electric distribution companies shall, with customer consent, make available direct meter access and electronic access to customer meter data to third parties, including electric generation suppliers and providers of conservation and load management services."[46] DER service providers are "providers of conservation and load management services." The Commission has the express authority with this provision to impose EDI and other data exchange protocols between the EDCs and DERAs.

Customer data that aggregators need access to include historical electricity usage data, Peak Load Contribution and winter peak load values, and curtailment event data. Access to data is critical for aggregators to be able to operate in the PJM market. This data needs to be obtained in a timely and reliable manner to register DERA customers with PJM, demonstrate compliance with multiple requirements, and financially settle with PJM following DERA dispatches and compensate customers. Today, data processes are difficult, and data is formatted inconsistently across EDCs. While there are individual issues with most EDCs when it comes to obtaining data, the biggest issue is that the process is burdensome in a manner that is completely

[46] 66 PA CS §2807(f)(3).

inconsistent with the digital economy of 2024. There is no streamlined way to obtain customer data in a reliable, timely, and consistently useful structure.

The current, largely manual, processes for obtaining customer data are (barely) acceptable today. As the DER market expands, CADRE expects the number of data transactions to increase exponentially. Unlike the historic usage information needed by EGSs to design products and prices for customers, DERA will require real-time data to manage electric load in real-time. Additionally, as DERs become more important to balancing the grid, the timeliness of data will increase in importance. It is not long before DERAs will need near real-time data to ensure compliance with PJM dispatch signals and to optimize DER portfolio value for the consumers. It will soon become impossible to keep up with manual requests. The Commission noted in its ANOPR Order sections of the Choice Act related to smart meters and AMI supporting "'direct access to and use of price and consumption information [and] information on their hourly consumption,' '[e]nabl[ing] time-of-use rates and real-time price programs' and 'support[ing] the automatic control of the customer's electricity consumption' by the customer, the EDC or a third party engaged by the customer or the EDC."[47] These are the types of products and services enabled by Order No. 2222. We urge the Commission to enact regulations to further support these products and services.

66 PA CS §2807(f)(3) requires "customer consent" before customer data is released to a third-party. The Commission should standardize forms for customer consent across the EDCs and it should also require the utilities to allow "electronic authorization" from customers to provide that consent. In turn, aggregators receiving the customer information should be required

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[47] ANOPR Order, p. 14, citing 66 PA CS §2807(g).

to agree to proper customer authorization practices, data maintenance, and confidentiality requirements.

The Commission should begin this journey of EDI modifications, standardization and data protection soon. As noted in the ANOPR Order, the EDCs indicated that "Parties need to know what data are wanted or needed before it can be determined how data are to be provided."[48] The implementation of Order No. 2222 will bring a fresh wave of data requests to the EDCs. The number of requests and the speed at which responses will be needed will continually increase. It will be more efficient to define and address these needs in advance of market opening than after the market opens.

CADRE Recommendation: The Commission should begin this journey and mandate a streamlined method for obtaining data. EDI is a potential solution, as it allows aggregators to request data for numerous accounts at once. The existing EDI portals should be revamped and standardized across utilities. In a perfect world, the PUC would develop a centralized data repository similar to the Smart Meter Texas portal and the Integrated Energy Data Repository[49] that is currently being developed in New York.

IV. H. 2. Commission Q: What DERA cybersecurity items require further evaluation?

CADRE's cybersecurity comments are presented below in Section IV. K. 1, below.

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[48] ANOPR Order, p. 50.

[49] New York State, IEDR RFP, https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource (last visited May 14, 2024).

IV. H. 3. Commission Q: What role will advanced metering infrastructure (AMI) data play in operational coordination?

CADRE has addressed this issue, while not directly, in other sections of this document. Meter data and specifically, device-level meter data will become more important every day. The EDCs' AMI infrastructure will be a critical component to ensuring reliable data is available in near real time. The Commission has long sought innovative products and services for its retail electricity customers. DERs and DERA participating in wholesale electricity market will unleash those products. The Commission should ensure that the EDCs are keeping up with the technological demands of the DER market.

IV. H. 4. Commission Q: How should the PUC ensure that processes are in place for efficient data exchange among and between Component DERs, DERAs and EDCs for customer authorizations?

It is important for the Commission to ensure that these processes are in place for efficient data exchange. A rulemaking process is probably not the best venue to ensure that this happens as data technology is very dynamic and the market is not yet open, so specific data needs are not known. CADRE recommends that the Commission convene a stakeholder group soon (long before this rulemaking process is completed), to begin formal discussions about data needs to facilitate the DER market. This stakeholder group could be a new offshoot of the EDIWG working group or the Commission could reconvene the working group that was set up in response to the Enerwise docket to investigate CSP access to data.

IV. I. Small Utility Opt-in Procedures

IV. I. 1. Commission Q: The PUC seeks comment on procedures for small utilities to "opt-in" to Order 2222, and permit their retail customers to participate in DERAs, consistent with Order 2222 and PJM's DAPM, and any specific changes to the PUC's policies and regulations that would facilitate the opt-in process.

CADRE has no specific recommendations on how to facilitate small utility opt-in to this market. The Commission should endeavor to make the process as easy and seamless as possible. Small utilities should be encouraged to opt-in. Small utilities should be able to make this decision without opposition. A small utility's decision to opt-in will have no bearing on customers other than providing those customers with an option to participate in DER aggregation activities or not. This decision will not bind customers in any manner.

IV. J. Potential PUC Oversight Of DERAs

IV. J. 1. Commission Q: The PUC seeks comment on whether the PUC may assert jurisdiction to regulate DERAs, and, if so, what requirements should the PUC impose on DERAs, consistent with Order 2222 and PJM's DAPM, and what specific changes to the PUC's policies and regulations would facilitate the PUC's exercise of authority over DERAs.

CADRE does not desire to be "unregulated." In fact, we have suggested a PUC licensing procedure for DERAs in section III. B, above. The PUC will have significant regulatory authority over EGSs that offer aggregation services. For DERAs that do not provide retail electric services, it is not clear that the Commission can regulate much outside of the interactions between the DERA and the EDCs.

Even if this legal hurdle did not exist, CADRE would implore the Commission to exercise extreme diligence in determining what are useful regulations and what regulations are or will become harmful to DER participants. DERs present the Commission with a transformational opportunity to reduce emissions, reduce costs and increase reliability with little or no cost to ratepayers. Regulations could mitigate the opportunity significantly or even eliminate it.

IV. K. Cybersecurity Considerations

IV. K. 1. Commission Q: The PUC seeks comments on whether it should impose cybersecurity standards or requirements on Component DERs, DERAs or EDCs, consistent with Order 2222 and PJM's DAPM, and any specific changes to the PUC's policies and regulations that would facilitate appropriate levels of cybersecurity in the implementation of Order 2222.

Cybersecurity and data protection are core issues for any business and are not electricity market specific. In the electricity market, technical standards organizations such as the National Institute of Standards and Technologies ("NIST"), North American Electric Reliability Corporation ("NERC") and the Institute of Electrical and Electronics Engineers ("IEEE") have already developed cybersecurity standards. For example, NIST was mandated by Congress, via the Energy Independence and Security Act of 2007, to coordinate standards for the development of the smart grid. Some of these standards are embedded now in manufacturing and development processes.[50] Cybersecurity standards have already been addressed by national technical standards organizations and do not need to be reinvented by the Commission. We urge the Commission to refrain from issues cybersecurity regulations because of the dynamic nature of network technologies and security, which could result in regulations that are outdated, literally, before they are implemented.

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[50] See: Cusick, Kerinia, Harry Warren and Versha Rangaswamy, *It's Time for States to Get Smart About Smart Inverters*, Center for Renewable Integration, October 2019, located at https://www.center4ri.org/publications/#smartinverter,.

IV. L. Distribution Level Benefits

IV. L. 1. Commission Q: The PUC seeks comment on whether and how it should account for the distribution level benefits of DERAs.

CADRE believes that the Commission and the EDCs should look to this DERA process as an opportunity to create a distribution platform that can be utilized at the wholesale level by PJM and DERAs and at the retail level by the EDCs and the DERAs. This platform will include the technical policy requirements discussed throughout these comments. The platform will be used to allow DERs and DERAs to participate in the wholesale market which will maximize returns to DER customers and minimize costs for non-participating customers. It could be used to allow DERs and DERAs to provide distribution level services so that the EDCs can delay or avoid investments, solve local reliability issues, manage energy and capacity cost exposure for their customers and other services. The platform would include streamlined interconnection processes, real-time data flow, access to metering data, including device level metering data and other attributes. This platform could be used to advance the Pennsylvania electric grid into a model that could be emulated by other states.

EDC use of the DER aggregations that will be developed under Order No. 2222 programs could also provide tremendous benefits to the EDCs, aiding in reliability and cost reductions for the distribution grid. The same DER aggregations built for the wholesale market could be used to relieve distribution congestion, alleviate constraints, avoid or delay costly investments in grid infrastructure and potentially for other functions. The wholesale aggregations, formed at no cost to distribution ratepayers, could and should be used by the EDCs to alleviate distribution constraints while simultaneously minimizing costs to EDC consumers.

We can point to neighboring states for support for this proposal. New York provides an excellent example of how these programs could work. The New York utilities have each implemented two separate demand response programs. The first, the Commercial System Relief Program ("CSRP"), is a program designed to minimize peak demand. It is triggered when forecast peaks reach certain points. When CSRP is called, resources are dispatched to reduce overall metered demand. This action lowers the system-wide capacity obligation, which keeps prices down for all customers. The New York CSRP programs are very similar in design and intent to the former Act 129 demand response programs.

New York's other demand response program, the Distribution Load Relief Program ("DLRP") is a local emergency relief program. Conditions that trigger a DLRP event include being one contingency away from a "Condition Yellow" or an active voltage reduction by network. These reliability measures can arise locally even when they do not rise to the level of an RTO dispatch. The Pennsylvania EDCs could implement similar solutions utilizing the previously formed DER aggregations to provide the same or greater level of benefits to the EDC's rate payers.

We can also look to Maryland for a state that is thinking proactively about distribution management from DERs. In Maryland's 2024 legislative session, it passed the Distributed Renewable Integration and Vehicle Electrification ("DRIVE") Act.[51] The DRIVE act is largely targeted at integrating bidirectional flow of electricity from electric vehicles ("EV"), acting as

[51] Maryland HB 1256, An Act concerning Electricity – Tariffs, Distributed Energy Resources, and Electric Distribution System Support Services (Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act).

DERs, into the distribution grid. In addition to utilizing EVs, the Act envisions additional DER services to avoid distribution grid capital expenditures. The Act requires that:

> On or before July 1, 2026, each investor–owned electric company shall submit a report to the commission evaluating:
>
> (1) the potential to avoid or defer electric distribution system capital projects through the use of time–of–use rates, demand–response and demand–side programs, and renewable on–site generating systems; and
>
> (2) the merits and feasibility of transitioning all customers to a time–of–use tariff on an opt–out basis.[52]

Pennsylvania formerly implemented EDC sponsored demand response programs under their respective Act 129 programs. These programs were aimed at curtailing system peaks in an effort to reduce costs. While the design of those programs was not ideal, they were effective in reducing costs for all ratepayers. The Commission should commit to developing similar EDC-specific DER and DERA programs going forward. If the EDCs developed programs to utilize existing DERs instead of investing in distribution infrastructure, customers will see lower prices, DERs will earn better returns on their investments and the distribution and transmission grids will be more reliable and resilient. Use of DER and DER aggregations to relieve distribution issues and participate in PJM's wholesale market at the same time does not amount to double compensation. Dual participation in such programs is allowed and endorsed by FERC.

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[52] Id., § 7-1003 (C).

IV. M. EDCs Acting As DERAs

IV. M. 1. Commission Q: The PUC seeks comment on whether and how it should mitigate conflicts of interest that may arise from an EDCs participating in wholesale markets as a DERA, consistent with Order 2222 and PJM's DAPM, and whether and what specific changes to the PUC's policies and regulations could facilitate such mitigation.

The Commission's question recognizes the natural conflicts of interest that would arise from EDCs acting as DERAs. To be clear, those conflicts are untenable. The EDC has the right to deny the registration of a DER or DER aggregation. The EDC has the right to override a PJM dispatch order of a DER or DER aggregation. If these powers are exercised just once in a scenario where the EDC is a DERA, it could cause irreparable harm to the competitive DER market.

According to the Choice Act, "the generation of electricity shall no longer be regulated" and "all customers of [EDCs] in this Commonwealth shall have the opportunity to purchase electricity from their choice of [EGSs]."[53] Historically, the monopoly EDC provided electricity, generation and transmission services. With implementation of the Choice Act, the EDC continues to provide distribution and transmission services to all consumers in its service territory on a monopoly basis. Generation is no longer a regulated service provided by the EDCs. Instead, the Commission established a competitive retail electricity market under the concept that EGSs can offer a variety of competitive generation products and services to consumers.[54] The purpose of unbundling and subjecting generation to competition is the

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[53] 66 Pa. C.S. §2806(a).
[54] 66 Pa. C.S. §2811.

recognition that "competitive market forces are more effective than economic regulation in controlling the cost of generating electricity."[55]

Of course, the intent of the Choice Act is clear with respect to retail sales of electricity. However, the Choice Act does not address DER and DERA. It is clear, however, that DER and DERA services are competitive services and are not part of the natural monopoly function of either transmission or distribution. There is no aspect of DER or DERA that are even remotely arguably a natural monopoly. As a result, the Commission should prohibit the EDCs from owning and operating DER aggregations for the purpose of participating in wholesale electricity markets.

As noted above, EDCs have the ability to delay or reject a DER or DER aggregation registration with PJM and the ability to override a PJM dispatch order of a DER or DER aggregation. Either of these actions could prove harmful to a competitive aggregator. An override of an energy or capacity dispatch could cause severe financial harm to a competitive DERA.

Many DERAs assist clients with financing, purchasing or leasing of DER tools, including storage assets, generation assets or other. Would an EDC do the same? How would it finance these assets? Who would bear the lifecycle risk of these assets? These are not business practices that a regulated utility should be engaged in. The Choice Act moved all of the electricity commodity risk to the competitive market. It should stay there.

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[55] 66 Pa.C.S. §2803(5).

The Choice Act removed the EDCs from participation in the wholesale market. The EDCs outsource wholesale electricity procurement for default service customers. They should not be allowed back into the wholesale market through DER aggregation services.

Finally, an EDC might have an incentive to not override its own aggregation because the financial penalties from PJM might be too large. That could lead to reliability problems. Alternatively, if they override their own aggregation dispatch and are assessed penalties from PJM, the EDC will seek to recover those costs from ratepayers.

The EDCs were removed from the commodity and risk management markets with the Choice Act. DER and DERA are energy and commodity businesses that bear significant market risk. Because the markets are competitive, the regulated entities should not be allowed to participate in the DER market. EDCs should not be wholesale market participants. EDCs should be prohibited from owning/operating DER assets, including component DER and aggregations of DER for the purpose of participating in wholesale electricity market.

If the Commission is inclined to allow EDCs to be wholesale market participants, it must institute severe financial penalties for discriminatory behavior against DERAs. It must mandate that all risk of market participation is borne by shareholders, not ratepayers and it must not allow ratepayers to subsidize their market participation in any way. Otherwise, the disparity in risk exposure will minimize competition in the aggregation market to the detriment of all customers in the market.

IV. N. Billing Issues

IV. N. 1. Commission Q: The PUC seeks comment on whether and how it could make the billing relationships between EDC customers, DERAs and EDCs transparent to the customer, consistent with Order 2222 and PJM's DAPM, and whether and what specific changes to the PUC's policies and regulations could facilitate such transparency.

The issues of metering, billing and EDI are all related, and effective regulations in these areas are important factors for the successful deployment of DER and DER aggregations. CADRE urges the Commission to address these issues in a complementary manner.

CADRE does not believe that any additional billing regulations will make the billing relationship more transparent to the customers. Additionally, we believe DERA billing falls outside of the Commission's jurisdiction. In this section, we recommend that the Commission issue new billing regulations for EGSs that offer DER/DERA services. Those new regulations would expressly wave the current EGS billing regulations in 52 Pa. Code § 54 when providing advanced services.

It is well established that DERAs are not and do not need to be EGSs, and vice versa. However, if an EDC customer received advanced DER Aggregation services, the billing requirements outlined in 52 Pa Code § 54 are inadequate to support an effective billing relationship. The constraints built into the billing requirements effectively limit the products and services that can be offered to customers because only specific types of products can be billed. Under the current billing requirements, an effective DERA bill statement cannot be rendered.

The current regulations for example, require a per kWh price[56] or unit price and therefore the products created are "per kWh" or unit price products.

DER activities are complex with bi-directional flows of electricity. The billing units might be non-standard, for example, a DER customer might be offered a flat rate of $20 per month for EV charging between the hours of 8:00 PM and 5:00 AM but might have disincentive charging rates of $0.20 - $0.30 per kWh in the summer months between the hours of 2:00 PM and 8:00 PM (the hours likely to be used by PJM to determine capacity obligations). Charging in other hours might be at a standard retail "per kWh" rate, or possibly not. (This product innovation is enabled by device-level metering.) The DER might be able to provide energy to the grid for an hour in the morning at $0.15 cents per kWh and then again in the afternoon for $0.20 per kWh. Load curtailment at the thermostat might be paid $5.00 per month, but the associated energy and capacity revenues accrue to the DERA. The DER contract might allow for the customer to keep 50% of ancillary service revenues and 100% of energy revenues earned from energy injections across a billing cycle. The iterations are almost unlimited. They do not fit in the format of a utility bill, the concepts of which were designed several decades ago.

Shown below are two residential electric bills. The first is a bill rendered to a customer in Texas participating in a DER pilot aggregation program. This invoice is notable in several regards. First, it does have some fixed $/kWh units billed. It also shows variable $/kWh units billed for energy sold back to the market. The variable priced "revenue" units are tied back to a table that is referenced, but not shown on the invoice. It also includes a large negative lump sum of $40.00 for Virtual Power Plant Credits. It includes the charges from the wires utility and

[56] 52 Pa. Code § 54.4(b)(3)(i)(A).

taxes. All of these charges, when netted, sum to a negative $13.14 monthly invoice, with an accrued balance due to the customer of over $700.

TESLA ELECTRIC

Tesla Energy Ventures, LLC REP #10296		Invoice Number	[redacted]
13101 Harold Green Dr.		Invoice Date	Feb 20, 2024
Austin TX, 78725, United States		Bill Period	Jan 16, 2024 - Feb 14, 2024
PUCT Certificate #10296		Payment Due By	Mar 7, 2024

Sold To

[redacted]

Account Number	[redacted]
ESI ID Number	[redacted]
Meter ID	[redacted]
Contract Exp. Date	Month-to-Month

Monthly Statement

Your average cost of electricity: -$0.036 / kWh

Current Charges	Qty	Rate	Amount
Tesla Electric Charges			**$28.16**
Peak	2.715 kWh	$0.124 / kWh	$0.34
Off-Peak	361.332 kWh	$0.077 / kWh	$27.82
Tesla Electric Sellback Credits			**-$25.35**
Real-time Energy Sold	445.009 kWh	Market Price (See Rate Table)	-$25.35
Tesla Virtual Power Plant			**-$40.00**
VPP Credits			-$40.00
TDSP Charges			**$23.96**
Base Charge	1	$4.39	$4.39
Home Energy Delivery Charge	364.047 kWh	$0.0538 / kWh	$19.57
Taxes			**$0.09**
PUCA			$0.09
Total Current Charges			**-$13.14**
Balance Forward			-$691.45
Total Amount Due			**$0.00**
Excess Sellback Credit Rollover			$704.59

The next invoice shown is an EDC invoice for a retail choice customer in the PECO service territory. By contrast, this invoice has only one line item for energy services and three separate line items for distribution system costs. No consumer value can be gained on the distribution side of the bill except for avoiding costs with conservation or DER participation. Under Order No. 2222, consumer value will be created on the energy side of the bill.

peco℠
AN EXELON COMPANY

Account Number: [redacted]

Page 2 of 3

1 Service Address [redacted] **$141.47** Electric Choice ID: [redacted]

Meter Information

Read Dates	Meter Number	Load Type	Reading Type	Meter Reading Previous	Meter Reading Present	Difference	Multiplier X	Total Usage
03/22-04/22	[redacted]	General Service	Tot kWh	5187 Actual	5208 Actual	21	40	840

Total kWh Used: 840

ELECTRIC RESIDENTIAL SERVICE

Service Period 03/22/2024 to 04/22/2024 - 31 days

PECO ELECTRIC DELIVERY		**$81.98**
Customer Charge		10.53
Distribution Charges	840 kWh X 0.08386	70.44
Distribution System Improvement Charge		1.01
ELECTRIC SUPPLY		**$59.52**
[redacted]		
Electric Supply Charge: 840 kwh @ 0.070860		59.52
TAXES & FEES		**-$0.03**
State Tax Adjustment		-0.03
Total Current Charges		**$141.47**

Shopping Information Box

When shopping for a competitive electric/natural gas supplier, please provide the following:

Electric Choice ID: [redacted]
Electric Rate: Electric Residential Service

If you are purchasing the energy you use from a competitive supplier, it is important to understand the terms of your contract and expiration date.

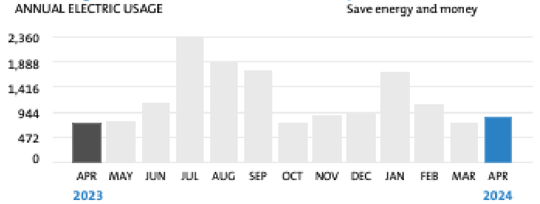
Message Center

From PECO:
New charges contain estimated total state tax of $5.62, including $4.84 for State Gross Receipt Tax.

Your estimated electric price to compare adder is $0.0943 per kWh, which includes ancillary charges and the purchased generation adjustment but excludes energy and capacity. This may change in March, June, September and December. For more information and supplier offers visit **PAPowerSwitch.com.**

Your Usage Profile
ANNUAL ELECTRIC USAGE

peco.com/smartideas
Save energy and money



Period	Usage	Avg Daily Usage	Days	Avg Daily Temp
Current Month	840	27.10	31	52
Last Month	720	25.70	28	51
Last Year	720	24.80	29	56

Avg kWh per Month	1,223
Total Annual kWh Usage	14,680

8752-03-0004124-0001-0000896

DER service providers operating in Pennsylvania could provide the Texas-style billing for their customers. They will have all of the usage data, the device level data, and net consumption data (even though they don't sell retail energy). Despite having all of that information, if retail energy was a component on the invoice, the Texas-style invoice shown above would be non-compliant with several regulations in 52 Pa. Code § 54.

With effective billing and metering technologies, billing information can be provided in near real time over an app or other computer-based technology. Customers will be able to know exactly what resources are being used in real time, whether it be solar, storage, system power or if the customer is curtailing anywhere (thermostat, EV charging, etc.).

Contracts are unique to each customer and might include any or all of EVs, generation, NEM, storage, demand response, and provide energy, capacity, and/or AS. Each customer could have a contract unique to its resource portfolio. As such, standardized bills, such as those required under current regulations are not suitable for a robust DER relationship. Standardized bills enable only standard products. Billing regulations constrain product innovation and delivery.

CADRE proposes that within the new DER-related regulations that a Customer information section be created, similar to the section applicable to EGSs in 52 Pa. Code § 54. This new section would exempt EGSs that are also providing DER services from 52 Pa. Code § 54.4 and 54.5. The new regulations for EGSs providing DER services could have requirements in it that would require the bill to reflect the terms of the contract. They could also require that the invoice be auditable, and that "market-based" prices be directly correlated (not equal to) to prices in the PJM market. This new regulatory section would also exempt EGSs providing DER services from the requirements included in 52 Pa. Code § 54.7 related to marketing requirements for DER products.

As noted above, a DERA can operate in the Commonwealth without selling retail electricity. That DERA could offer the customer any type of invoice it thought appropriate for the services it provides. Because the aggregator is selling into the wholesale market and not to the retail customer, the aggregator-only billing statement falls outside the jurisdiction of the Commission. The DERA can create the invoice best suited for the customer and the contractual relationship with the customer. Under the current framework, EGSs offering DER services would be constrained to the billing framework outlined in the current regulations. The Commission has been seeking innovative products and services from EGSs for a while. These products and services can be delivered in a comprehensive manner if the Commission will enable them.

It is also important from a competitiveness and market efficiency perspective. If an effective DER relationship can only be achieved by an entity that does not sell electricity to retail customers, the retail products and services offered by EGSs will always be limited and inefficient.

CADRE Recommendation: Create new Pa. Code sections in Title 52, under the heading "Customer Information" as follows:

- **§ 78.30 EGSs offering DER Aggregation Services shall be exempt from the billing requirements outlined in 52 Pa. Code § 54.4 – 54.5 for customers who are receiving DER Aggregation services.**
- **§ 78.31 An EGS bill to customers receiving DER Aggregation services must be reasonably understood and include all contracted pricing components.**
- **§ 78.32 The bill elements on an EGS invoice that includes DER Aggregation services must be reasonably auditable by the consumer.**

- **§ 78.33 The bill elements on an EGS invoice that includes DER Aggregation service that are based on "market-based" rates must be directly correlated (not equal) to the hourly or other settled time interval price of the equivalent product that is cleared in the PJM or successor wholesale electric market.**
- **§ 78.34 EGSs offering DER Aggregation Services shall be exempt from the marketing requirements outlined in 52 Pa. Code § 54.7 when marketing DER Aggregation Services.**

IV. O. Equity Concerns

IV. O. 1. Commission Q: The PUC seeks comment on how to identify and address potential equity concerns associated with the expected proliferations of DERAs in Pennsylvania in the coming years.

CADRE understands these equity concerns and believes that the savings from reduced energy costs will more than offset any increases in distribution costs. In fact, if the wholesale aggregations were used by the EDCs in a thoughtful and productive manner, as described in the Distribution Level Benefits in Section IV. L. 1, above, they could result in downward pressure on distribution rates also. By deploying DER and DER aggregations under state retail programs, EDCs may be able to delay and/or avoid distribution upgrades.[57]

Additionally, with appropriate regulation, there is no reason that low-income customers would not be able to participate in DER aggregations. DERs do not necessarily require costly investments. A participant can join an aggregation of controllable thermostats, or other home devices. Also, under the appropriate interconnection, ownership, and contracting structures, low-income customers could install storage devices and/or rooftop solar. CADRE believes that DER and DER aggregations are very attainable and beneficial to low-income customers.

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[57] See, for example: Mims Frick, Natalie, Snuller Price, Lisa Schwartz, Nichole Hanus, and Ben Shapiro, *Locational Value of Distributed Energy Resources,* Lawrence Berkely National Laboratory, February 2021. Found at: https://live-etabiblio.pantheonsite.io/sites/default/files/lbnl_locational_value_der_2021_02_08.pdfCitation?

In Section IV. B. 3, above, CADRE urged the Commission to be creative in allowing NEM resources to participate in wholesale markets, for example, by compelling the EDCs to accept device-level meter data. If NEM use was expanded, this would put further downward pressure on capacity and energy prices, benefiting all customers.

NEM has been a key policy mechanism for ensuring solar and other DERs are accessible to low- and moderate-income utility customers. According to data in a recent Lawrence Berkey National Laboratory ("LBNL") report[58], Pennsylvania has developed a NEM program that is accessible to lower-income customers. The LBNL Report examined the income, demographic, and other socio-economic trends among residential rooftop solar adopters in the United States. The LBNL Report found that Pennsylvania has one of the highest levels of solar adoption by low- and medium-income communities in the nation. According to the study, 29% of Pennsylvania's solar adopters have an annual household income of less than $50,000. Another 41% of Pennsylvania's solar adopters have incomes between $50,000 and $100,000. The LBNL report shows the national median annual household income to be $69,000.[59] The chart below shows income distribution data specific to Pennsylvania from the LBNL Report.[60]

Improving on the current NEM practices, including interconnection reform, enabling device-level metering and refraining from imposing unnecessary regulations in other areas will help this market flourish to the betterment of all consumers, including low- to middle-income consumers.

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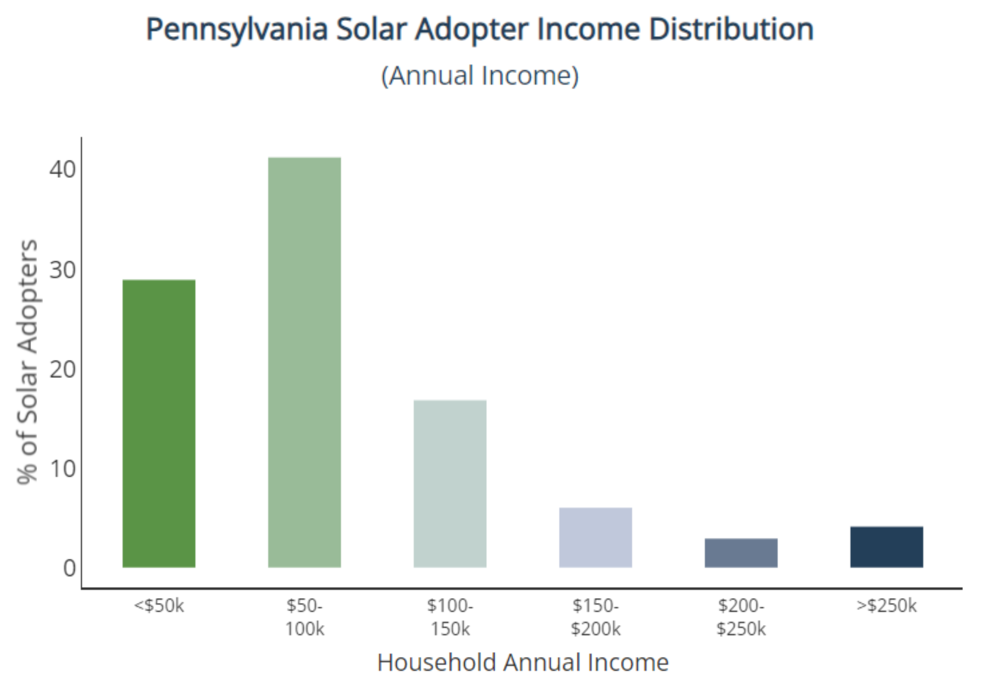
58 "R*esidential Solar-Adopter Income and Demographic Trends: 2023 Update," Lawrence Berkeley National Laboratory.* December 2023. ("LBNL Report")

59 *Id.*

60 *Id.* State-specific data from this study can be found at: https://emp.lbl.gov/solar-demographics-tool.



In Section IV. C. 5, above, CADRE urged the Commission to consider on-bill financing for interconnection costs and to prohibit the EDCs from demanding upfront payments for interconnection costs. On-bill or other financing for interconnection costs could alleviate some of the financial burden of deploying DER.

DERs are currently available to low-income customers including controllable thermostats, EV charging management, in-premise storage devices, and according to the LBNL Report, rooftop solar. These resources might be provided to customers at zero or discounted costs and managed by the DERA to maximize the value of the resources. However, other regulations that limit the sale of electricity to low-income customers, or compel certain billing units, will severely hamper the delivery of DER services to these customers. DERs can be provided by companies that do not provide electricity, but it is a natural business case for those that do provide electricity to expand their offerings to include DERs.

DERs will result in lower emissions, lower prices and provide increased reliability to all customers, including non-participants. Equity advocates in Pennsylvania should fully embrace the proliferation of DERs.

V. Conclusion

CADRE appreciates the opportunity to comment on these very important electricity market issues. We pledge to work with the Commission and other stakeholders throughout this process to ensure a smooth transition to a fully integrated DER market. CADRE represents the views of several of the largest organizations participating in these markets and market development efforts. We urge the Commission to consider our comments commensurately.

Respectfully Submitted,

Coalition Advocating DER Regulation Efficiency
May 29, 2024

CERTIFICATE OF SERVICE

Distributed Energy Resources Participation in Wholesale Markets	: :	Docket No. L-2023-3044115

I hereby certify that on this day, May 29, 2024, I served a copy of Coalition Advocating for DER Regulation Efficiency's ("CADRE") Comments in accordance with the requirements of 52 Pa. Code § 1.54.

Word®-compatible copies have been circulated to the contact persons for this matter via electronic mail in accordance with the Commission's Order posted on February 22, 2024, in this proceeding.

Dated this 29th day of May 2024

SERVICE BY EMAIL ONLY

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