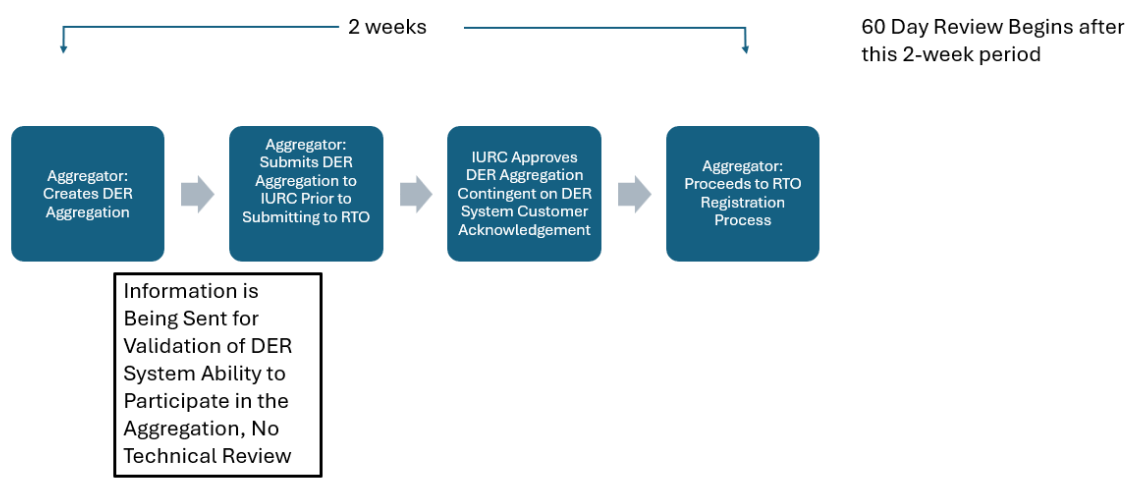
Indiana Investor-Owned Electric Utilities' Comments on Indiana Utility Regulatory Commission Rulemaking for FERC 2222 Implementation

Duke Energy Indiana, LLC, Indianapolis Power & Light Company d/b/a AES Indiana, Indiana Michigan Power Company, Inc., Northern Indiana Public Service Company, and Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (collectively the "Indiana Investor-Owned Electric Utilities" or "Utilities") appreciate the opportunity to provide reply comments to comments submitted after the May 29, 2025 meeting concerning the Indiana Utility Regulatory Commission's ("IURC") rulemaking for implementation of FERC Order 2222. The Indiana Investor-Owned Utilities' comments focus on the registration frameworks for DER Aggregators and DER Aggregations.

Executive Summary

The Utilities recommend pre-registration for DER Aggregators. Each utility has experience with the existing Interconnection Customer review process and the recognition that an application will require time for validation is essential. As noted later in this document, in Section VI, the need for this level of initial review is essential given that DER systems are now changing their participation. For example, if there are three DER Systems, DER System A, DER System B and DER System C and the Aggregation is A+B+C and System B is changing its system settings, the Aggregation would require a Supplemental Review. To illustrate this Supplemental Review timing, please see Figure 1 below that outlines this Pre-registration process.

Figure 1



I. Introduction and Summary

The Indiana Utilities support an Indiana implementation of FERC Order No. 2222 that enables market participation by distributed energy resource aggregations (DERAs) while preserving distribution system safety and reliability. These comments present a practical, consumer-focused framework that integrates state-level oversight with distribution-level engineering and operational coordination.

The Indiana Utilities recommend:

- A state-level registration for DER Aggregators (IURC-administered) that establishes minimum qualifications, consumer safeguards, and a transparent roster. (Section III)
- A utility/RERRA-level registration for DER Aggregations (distribution reliability review and operational coordination) designed to run within FERC's 60-day window and, when truly needed, use the RTO/ISO tariff's "exceptional circumstances" pathway for limited extensions. (Section IV)
- Clear roles, standardized data requirements, anti-double-counting guardrails, cybersecurity and consumer-protection baselines. The Utilities do not recommend an open database of consumer information. (Section IV)
- Interconnection process alignment through an "Aggregation-Readiness Addendum" and a supplementary interconnection pathway for already-interconnected DERs when changes in the way retail reviews were done. (Section V & VI)

II. Guiding Legal and Policy Principles

- FERC Orders 2222 / 2222-A: RTO/ISOs must allow DERAs to participate and set tariff-based information, metering/telemetry, and coordination rules. Distribution-utility review of a DERA is capped at 60 days; any additional time must be provided through the RTO tariff in exceptional circumstances.
- Indiana statutory context: IC 8-1-40 provides the Commission authority over DER interconnection and related rules; the IURC can require transparent processes that protect reliability and customers as Indiana implements Order 2222.
- Small-utility (co-op) opt-in: For utilities selling ≤4 million MWh, participation is opt-in via the RERRA; state rules should respect that governance and avoid one-size-fits-all mandates.

III. DER Aggregator Registration with the IURC (State Level)

Purpose: Establish a floor of competence and accountability for market actors interacting with Indiana customers and utilities while keeping wholesale qualifications in the RTO/ISO domain.

A. Registration & Qualifications

- Entity identity: legal name, FEIN, principal officers, service territories;
- Scope of services: products offered (energy, capacity, ancillary services), retail interactions, data practices;
- Demonstration of RTO/ISO eligibility: evidence of meeting MISO/PJM DERA requirements;
- Contacts for customers, IURC/CAD, and utilities;
- Bonding/insurance and consent to Commission jurisdiction for customer protection matters;
- Grounds for suspension/decertification: fraud, repeated violations, unauthorized enrollments, failure to honor utility emergency override directives, or violation of PJM/MISO

tariffs. The Commission should provide notice and an opportunity to be heard before decertification;

- Optional: Registration/license fee to support administration and consumer protection (to be considered by the Commission).

B. Consumer Protection

- Plain-language disclosures: non-affiliation with utility; how wholesale enrollment interacts with retail tariffs; potential loss of legacy benefits; fees/exit terms; complaint contacts;
- Proof of customer authorization for data access/enrollment; audit trails and quarterly reports to CAD;
- Financial calculators (scenario-range; no guaranteed outcomes);
- Fraud deterrence: penalties for unauthorized enrollments.
- The IURC would be responsible for reviewing and determining authenticity.

C. Customer Notice

Upon deeming a DERA application complete, the IURC will notify affected customers (e.g., mail or email) that enrollment may alter existing retail program benefits and provide an opt-out path prior to technical analysis. This reduces the risk of unintended dual compensation and ensures informed participation. The Indiana Utilities recognize that is important for customers to understand what is involved in the DER Aggregation registration and enrollment. If a customer is opting out of a retail program, this notice allows for the individual DER to acknowledge this change for transparency and understanding. This needs to create flexibility with the DERA that customers can opt out with DERA Prior to DERA submitting application for their Aggregation approval

IV. DER Aggregation Registration with the Relevant Utility/RERRA (Distribution Level)

Purpose: Ensure each DERA can operate safely and reliably on the distribution system, avoid double counting, and meet operational coordination needs—without violating FERC's 60-day limit.

A. Standardized Data Package (submitted with RTO/ISO registration)

- Interconnection identifiers, service address, feeder/substation, EPNode/CPNode;
- Resource types/capabilities (injection/withdrawal, reactive power capability, ramping), committed MW, telemetry specifications, baseline/M&V method;
- Intended market products (energy, capacity, reserves, frequency/VAR support);
- Retail tariff status for each component (e.g., EDG/net metering/DR) to prevent double counting; and
- Attestations regarding unique enrollment (no dual enrollment for the same service) and data privacy/security.

B. Timeline and the 60-Day Cap

The distribution review runs concurrently with RTO/ISO registration and must be completed within 60 days. Any limited extension occurs only under the RTO/ISO tariff's "exceptional circumstances" provision.

- The IURC should view incomplete and/or inaccurate data submissions as grounds to qualify as an exceptional circumstance due to the delays it will cause. This needs to be explicitly documented in the dispute resolution or IURC process. There is no specificity currently in place on what constitutes an exceptional circumstance for RTO/ISO process.

D. Engineering Review & Cost Responsibility

- DERA-level reliability assessment: thermal/voltage margins; protection coordination; inverter-based resource settings and expected dispatch profiles; potential interactions with feeder switching plans;
- There should be a mechanism to charge an aggregator for the impact study for the DERA review.
- If upgrades or added metering/control are needed solely to enable the DERA, the aggregator bears the cost;
- Study outcomes documented with operating conditions (e.g., export caps, PF/VAR obligations, telemetry requirements).
- Consider implementing an Aggregator Distribution Access Fee, to be applied either at the state level or by individual utilities.
    - This fee would be assessed based on the total aggregated system size of participating entities and is intended to help offset the increased maintenance and operational demands placed on the distribution system by aggregator activity.
    - By establishing such a fee, the Commission can help ensure that the costs associated with supporting aggregator access are equitably distributed and not unfairly borne by ratepayers who do not directly benefit from these services.

E. Operational Coordination

- Day-ahead schedule submission and real-time telemetry (5-minute granularity for ancillary services where applicable);
- Utility emergency override/cease-to-energize authority with notice to RTO/ISO and aggregator; event logs retained 5 years;
- Planned outage notifications;
- Unique DERA ID and membership ledger maintained by the utility for operations and settlement validation.

F. Dual Participation & Double-Counting Controls

Dual participation is permitted only for distinct services with separate M&V. Simultaneous compensation for the same service across retail and wholesale programs is prohibited.

G. Switching Limits

Minimum 12-month participation in a DERA before switching aggregators or re-entering retail programs, with exceptions for equipment failure, change of premise ownership/tenancy, or regulatory disqualification.

H. Dispute Resolution

Retail/interconnection/consumer disputes: IURC/CAD. Wholesale registration/settlement and any exceptional-circumstances extensions: RTO/ISO dispute processes.

I. Temporary Ramp Cap (to be requested by the Commission)

The Indiana Utilities suggest considering a time-bound ramp by feeder/substation or MW portfolio for 12 months. This is not meant to be a barrier to DER Aggregations, but necessary as Utilities, Regulators, Customers, Other Stakeholders all prepare for this new market paradigm. For example, Utilities do not yet utilize this type of "market dispatch" at the Distribution Level, we currently as vertically integrated utilities, do this only at the Transmission level. This Ramp period/Cap could be tied to telemetry readiness, data collection, and grid reliability performance and assurance, followed by a scheduled review and adjustments. This is to help with an operational learning curve to allow utilities and aggregators to refine coordination processes (day-ahead schedules, telemetry integration, override procedures) before scaling up. This is a temporary not permanent cap tied to reliability and keeping customer protections in mind.

V. Interconnection and Aggregation-Readiness

Add an "Aggregation-Readiness Addendum" at interconnection application time (no new gate). Collect PCC export limits, feeder/substation mapping, IEEE 1547-2018 settings, telemetry readiness, and retail program status so utilities have the data needed for DERA review within the 60-day window.

- For one DER system, the PCC export characteristics: non-export vs. export configuration; approved maximum export (kW/kVA) at PCC;
- Feeder/substation mapping: Feeder ID, Substation, lat/long, and single-line diagram. Feeder /Substation information to be inputted by utility after submission. There should not be a database of what feeders/substation a individual DER is connected to;
- IEEE 1547-2018 settings on file: Volt/VAR, Volt/Watt, Frequency-Watt, ridethrough categories and trip points/timers, PF setpoints; The Utilities recognize that this difference is likely captured in the interconnection agreement review and when the DER system was interconnected would drive their settings. If an aggregation is going to perform different services as part of participating in the aggregation, the DER system may require different settings.
- Telemetry, metering & M&V: interval capability (e.g., 15-minute AMI vs. 5-minute), revenue-grade meter or meters as applicable, real-time telemetry for large resources;
- Operational controls & override: utility-visible, lockable disconnect; remote trip/override readiness if required;

- Retail program interactions: current status (EDG/netting/DR) and non-binding DERA participation intent;
- Cybersecurity & data privacy: secure communications, credentialing, consent.

No new gate: Completing this Addendum does not create a new interconnection review step or delay permission to operate. It standardizes data needed if the resource later registers in a DERA.

VI. Supplementary Interconnection Review for Already-Interconnected DERs

Purpose: Provide a clear pathway for DERs that are already interconnected to undergo a focused, time-efficient supplementary interconnection review when material changes are proposed to enable DERA participation, while respecting the FERC 60-day coordination timeline. What this supplementary review will be used for is to determine if the interconnection of existing assets that are participating in an aggregation are the same as studied for interconnection. An example of this is when net metering customers were approved for interconnection for exporting only kW at 100% PF. If a DER asset then decides to provide a different operating characteristic, such as exporting VARS, then the assets should have to go through a supplementary review to ensure no adverse effects on the distribution system.

A. Triggers for Supplementary Review

- Export status or level changes: shift from non-export to export, changes in inverter settings, moving from exporting only kW to now kVAR, or increase of approved maximum export at PCC; These operational settings, as noted in the start of this section, impact how the aggregation behaves and how it is called upon.
- Topology changes: new POI, feeder/substation change, or rephasing affecting protection/voltage coordination;
- Resource configuration changes: addition of storage that materially alters net injections; addition of synchronous generation/CHP; changes to control/protection (e.g., DTT requirement, altered ridethrough profiles);
- Telemetry/controls that affect safety or operations: new remote-control scheme interfacing with protection or islanding logic;
- Aggregation-driven commitments that require revising the PCC export cap or protection/operational settings;
- Material change in operating profile: participation in ancillary services requiring different dynamic response or telemetry granularity.

B. Scope of Supplementary Review

- Validation of PCC export limits and need for any revised caps or operating conditions;
- Protection coordination and ride-through behavior under synchronized DERA dispatch scenarios;
- Voltage/thermal assessments on the affected feeder/transformer sections under expected DERA commitments;

- Telemetry/metering sufficiency for required market products and system operations;
- Cybersecurity posture for any new control/telemetry interfaces; and
- Documentation updates: settings sheets, single-line, relay coordination summaries.

C. Process & Timeline Coordination

- Where feasible, the supplementary review is conducted before registration to ensure all Interconnections have been reviewed properly. This will ensure the DERA distribution review to fit within the 60-day window;
- If a limited extension is necessary due to exceptional circumstances (e.g., complex multi-feeder ancillary service portfolios), the utility will seek such extension solely through the RTO/ISO tariff process;
- Interim operating conditions may be applied to allow partial participation while upgrades are completed, where safe and practical.

D. Cost Responsibility & Outcomes

- Costs for studies, metering/telemetry additions, and distribution upgrades required solely for DERA participation are borne by the aggregator/participant consistent with Commission-approved tariffs; For example, the IAC notes the study process required now for Interconnection. The Level III Interconnection Impact Study is currently required and the Utilities recommend adding “DER Aggregators” to this section of the IAC. This suggested State Level Registration process could include payment terms.
- Possible outcomes: (i) approved as-is; (ii) approved with conditions (export caps, settings adjustments, telemetry); (iii) approval contingent on specified upgrades; (iv) denied with documented technical rationale.

E. Grandfathering and Exceptions

Pre-existing interconnection approvals remain valid for their original operating characteristics; supplementary review is only triggered by material modifications as defined above. Non-material or operating changes proceed without additional interconnection steps.

VII. Implementation Timeline and Next Steps

MISO Compliance Filing: FERC Docket No.ER22-1640
MISO Order 2222 implementation milestones currently anticipate DERA enrollment beginning June 1, 2029, with day-ahead/real-time market participation starting January 1, 2030, and capacity market participation June 1, 2030.
PJM Compliance Filing: FERC Docket No. ER22-962
Energy and Ancillary Services Implementation Date: February 1, 2028
Capacity Market Implementation Date: 2028/2029 Capacity Year (from June 1, 2028, to May 31, 2029). This matches with the proposed implementation timeline starting February 1, 2027. The 2028/2029 Capacity Year Auction is slated to be held in May 2026.

Utilities should align internal tooling, telemetry, and customer-facing processes to these dates while monitoring any RTO/ISO updates.

Indiana IOUs should continue coordinated working sessions, align on standardized data packages, and pilot operational coordination (e.g., telemetry integration, customer notices) in advance of market go-live.

Appendix

Definitions

- DER: Distributed Energy Resource
- DERA: Distributed Energy Resource Aggregation
- DEAR: A DEAR is an aggregation of individual DERs, such as solar, wind, and battery storage, that are managed by a single entity called a DER aggregator
- RTO: Regional Transmission Organization
- ISO: Independent System Operator
- IURC: Indiana Utility Regulatory Commission
- CAD: Consumer Affairs Division
- PCC: Point of Common Coupling
- POI: Point of Interconnection
- M&V: Measurement & Verification
- RERRA: Relevant Electric Retail Regulatory Authority
- EPNode: Elemental Pricing Node
- CPNode: Commercial Pricing Node
- MISO: Midwest Independent System Operator
- PJM: PJM Interconnection LLC
- kW: kilowatt
- kVAR: reactive power
- PF: Power Factor

Appendix A – Aggregation-Readiness Addendum (Template)

1. A. General & Premise Information (customer/legal name; service address; account and meter number; primary contact; site latitude/longitude).
2. B. PCC & Electrical Configuration (nominal voltage; level; export vs. non-export; approved max export at PCC; reverse-power/export-limiting device; visible, lockable disconnect location).
3. C. Feeder/Substation Mapping (Feeder ID; circuit phases; Substation/bus; upstream protective devices; single-line diagram).
4. D. DER Technology & Ratings (technology; make/model/firmware; nameplate AC/DC; reactive power capability; storage charge/discharge/kWh).
5. E. IEEE 1547-2018 / UL 1741 SB Conformance & Settings (voltage/frequency ride-through; - Volt/VAR; Volt/Watt; Frequency-Watt; PF; anti-islanding method; remote setting adjustment capability).
6. F. Metering, Interval Data & Telemetry (settlement boundary; AMI/revenue-grade; real-time telemetry protocol and points; cybersecurity contact).
7. G. Operational Coordination & Emergency Controls (override/cease-to-energize readiness; day-ahead schedule availability; outage notification channel).

8. H. Retail Program & Wholesale Participation Intent (current retail program; acknowledgment of no dual compensation for same service; intended wholesale products).
9. I. Data Privacy & Consent (specific consents for distribution safety studies, DERA coordination, anti-double-counting, settlement validation, cybersecurity incident response).
10. J. Attestations (as-built conformance; material modification triggers; settings maintenance; emergency override compliance; no dual compensation for same service).

Appendix B – Standardized DERA Submission Data Schema (Informative)

- DERA_ID (to be assigned by utility upon completeness);
- Aggregator legal name; RTO/ISO market ID; primary contact;
- Component list: account no.; meter no.; service address; feeder ID; substation; lat/long; resource type; nameplate/capability; committed MW; telemetry class; retail program status;
- Intended market products; baseline/M&V method; telemetry protocol and interval;
- Attestations: no dual enrollment for same service; data privacy; emergency override compliance.

Appendix C – Customer Notice (Template)

Subject: Notice of Pending Enrollment in a Distributed Energy Resource Aggregation (DERA)

Body: Our records indicate that a third-party DER Aggregator has proposed to enroll your DER in a DERA that may affect your current retail program benefits (e.g., EDG/netting/DR). Please review the enclosed summary and respond within [X] days if you wish to opt-out. Enrollment may change billing, settlements, and program eligibility. For questions, contact [utility contact] or [CAD contact].

Appendix D – Dispute Resolution Map

• Retail/interconnection/consumer issues → IURC/CAD processes.
• Wholesale registration/settlement issues and exceptional-circumstances timing extensions → RTO/ISO dispute processes.
• Emergencies/override events → utility operational protocols with after-action reporting to RTO/ISO and parties.

Appendix E – Telemetry & Settings Minimums (Informative)

Minimum telemetry granularity should reflect the market products sought (e.g., energy only vs. ancillary services). IEEE 1547-2018 functional settings should be recorded and maintained; changes coordinated with the utility.