Session 1

Welcome

Ryan Silvey, Chairman,

Missouri Public Service Commission

Session 2

Background on DR in Missouri

Whitney Payne, Senior Counsel,
Missouri Public Service Commission

Session 3

An Overview of FERC Orders 2222 and 2222A

Elliott Nethercutt, Principal Researcher, NRRI

An Overview of FERC Order 2222 and 2222A

Elliott J. Nethercutt – NRRI

Missouri Public Service Commission
FERC Order 2222 Informational Workshop
June 29, 2021

Agenda

- Background
- FERC Orders: Overviews and Recent Developments
- Potential Regulatory Implications for the Missouri PSC

Background

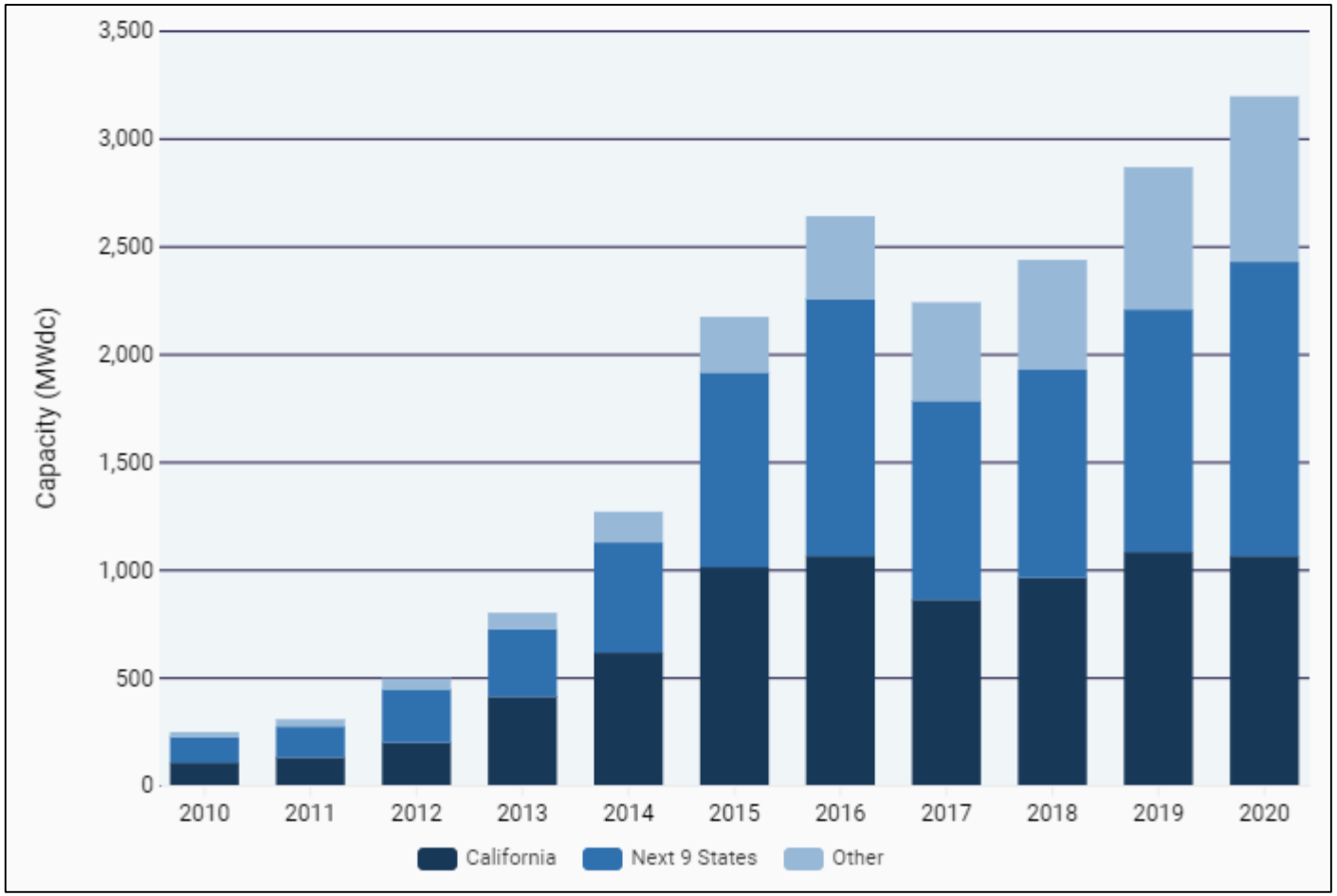
Background

- What are Distributed Energy Resources?
  - Small-scale power generation or storage technologies (from 1 kW to 10,000 kW)
  - Capable of "providing an alternative to, or an enhancement of the traditional electric power system." (FERC Order 2222 Fact Sheet)
  - Can be connected to a utility's distribution system, subsystem, or behind a customer meter
  - May include electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage or electric vehicles and their charging equipment

Source: Wood Mackenzie

Background

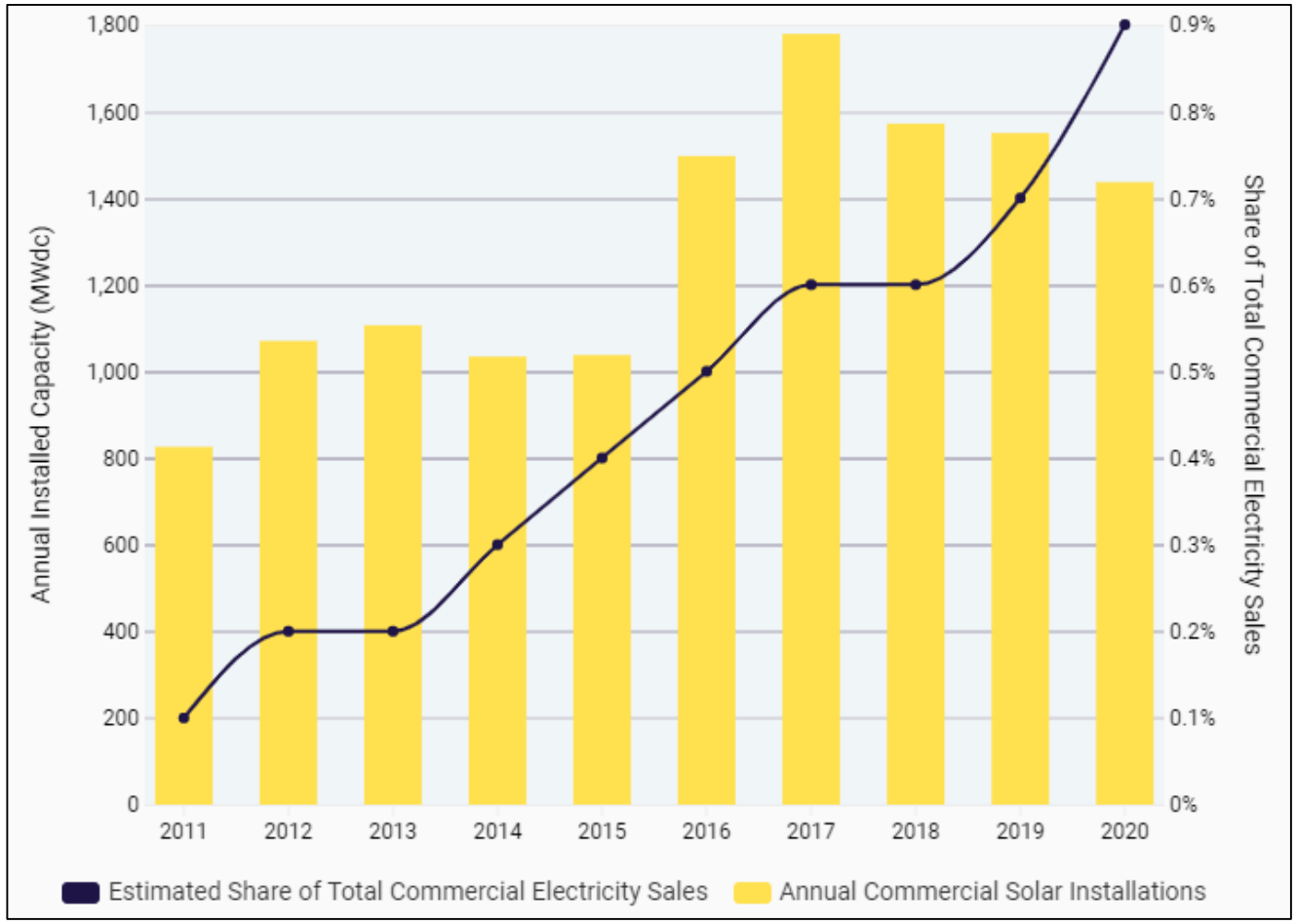
Annual Residential Solar PV Installations



Source: SEIA

Background

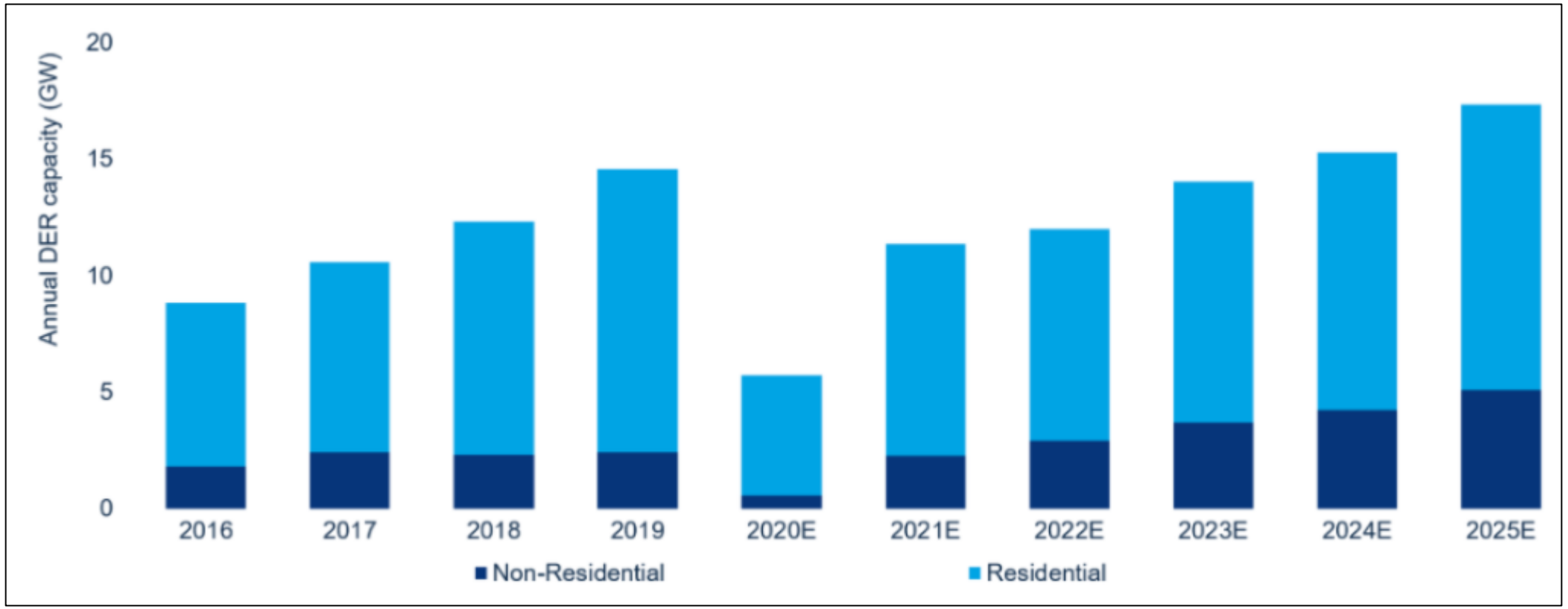
Commercial Solar PV Installations & Penetration Growth



Source: SEIA

Background

Annual Net DER Capacity Change



Source: Wood Mackenzie

FERC Orders: Overview and Recent Developments

FERC Orders: Overviews and Recent Developments
Order 2222

- September 17, 2020: FERC adopted a final rule that enables distributed energy resources (DERs) to participate in the regional organized wholesale capacity, energy and ancillary services markets
- FERC-identified benefits:
  - Lower costs for consumers through enhanced competition
  - Increased system flexibility and resilience
  - More innovation within the electric power industry
- In cases where there are DER aggregations composed of both DR and non-DR resources, FERC clarified in Order No. 2222-B that the requirements in Order No. 745 would apply to DR resources participating in heterogeneous aggregations

FERC Orders: Overviews and Recent Developments
Order 2222

- Each RTO/ISO must review (and potentially revise) tariffs to facilitate market participation by DER aggregations, including provisions to:
  - Establish them as a type of market participant
  - Allow them to register under one or more participation models that accommodate their physical and operational characteristics
  - Establish a minimum size requirement (not to exceed 100 kW)
  - Address locational requirements, distribution factors, and bidding parameters
  - Address information and data requirements (including metering and telemetry requirements)
  - Address coordination with the system operator (RTO/ISO), the distribution utility, and the relevant electric retail regulatory authorities (RERRAs)

FERC Orders: Overviews and Recent Developments

Order 2222 – ISO/RTO Responses

ISO/RTO	Status
CAISO	• CAISO Board of Governors approved three tariff revisions in October 2020 related to energy storage and distributed energy resources • Conducting comprehensive gap analysis between current distributed energy resource provider provisions • Mostly in compliance
ISO-NE	• Initiated a Key Project to engaged in several formal stakeholder meetings and discussions with state officials
MISO	• Acknowledged substantive tariff edits are needed for compliance • Distributed Energy Resources Task Force (DERTF) is tracking MISO's compliance filing and has developed proposed data requirements • DERTF has also developed/submitted initial comments and an informational filing containing a detailed stakeholder process schedule
NYISO	• Mostly in compliance
PJM	• DER & Inverter-Based Resources Subcommittee (DIRS) continues to iterate on the DER design for compliance • Collecting feedback from stakeholders and updating proposal accordingly
SPP	• Established Task Force responsible for identifying needed changes to governing documents for compliance • Identified action items needed to work towards compliance, including data collection and survey efforts

FERC Orders: Overviews and Recent Developments
Order 2222-A

- March 18, 2021 FERC order clarifies that DR that is part of a heterogeneous supply group of DERs can participate as a DER aggregation
- Reverses the DR "opt-out" provision, which allows RERRAs to reject offers from DR aggregators in states where the practice is not allowed
- State and local regulators would no longer be able to block a DER aggregation from participating in the wholesale markets because it includes DR

FERC Orders: Overviews and Recent Developments

Order 2222-B

- June 17, 2021: FERC set aside a prior decision not to extend the Order No. 719 opt-out to DR resources that participate in heterogeneous DER aggregations
- FERC acknowledged that a number of states broadly prohibited DR participation in energy markets and that those states—and other entities affected by the opt-out—may not have anticipated that this proceeding would call into question those broad prohibitions
- To ensure an adequate opportunity for interested entities to comment on the Order No. 719 opt-out, FERC extended the comment periods in Docket No. RM21-14-000

FERC Orders: Overviews and Recent Developments

Orders 719 and 719-A

- Issued October 17, 2008, FERC directed each RTO/ISO to amend market rules to accept bids from distributed aggregators of retail customers (ARCs) that provided at least 4 million MWh during previous fiscal year
- Applies specifically to cases where the RERRA is exercising the DR opt-out that prohibits the ARCs from bidding DR into organized markets
- On March 18, 2021, FERC issued a notice of inquiry (NOI), seeking comment on whether to revise this regulation
- Currently, 18 states, including Missouri are utilizing the Order 719 opt-out provision

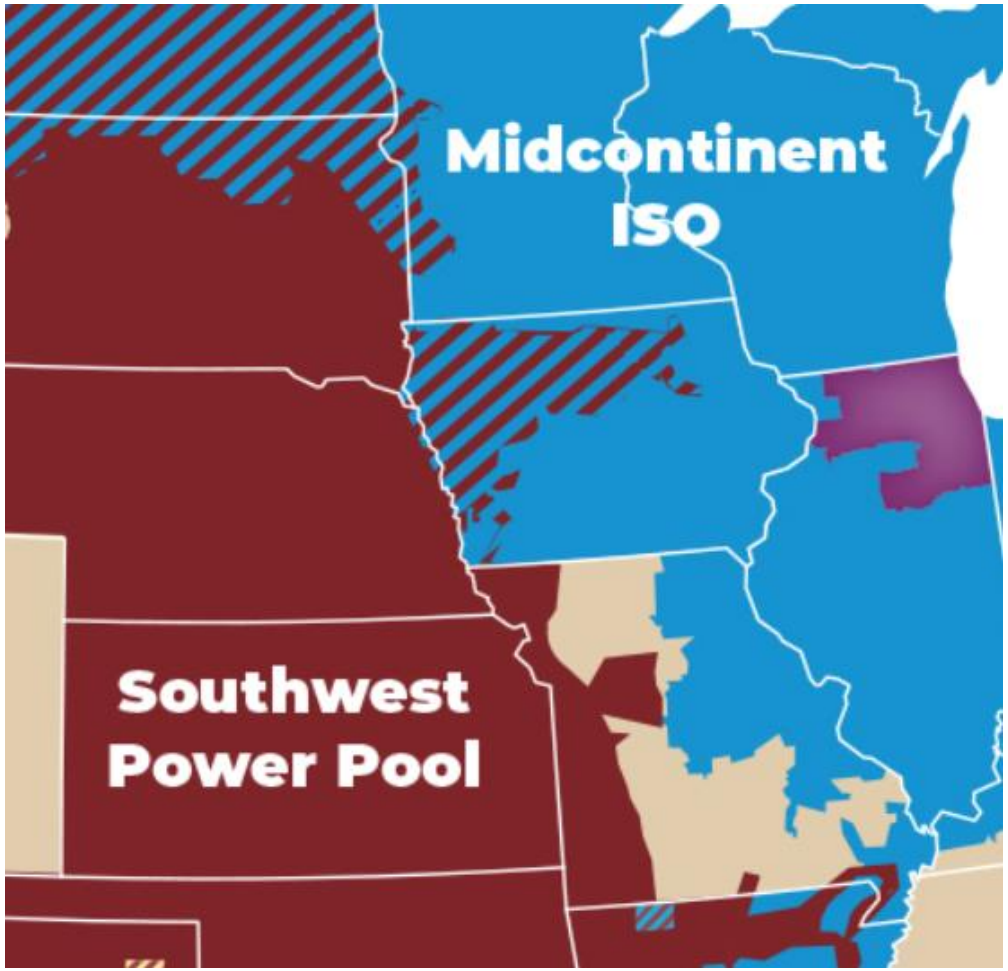
FERC Orders: Overviews and Recent Developments

RM21-14: Notice of Inquiry on DR opt-out

- Justification for disallowing the DR opt-out:
  - Significant legal, policy, and technological developments during the past decade
  - Allowing an ARC to act as an intermediary for many smaller retail loads (too small to participate in markets individually) can improve competitiveness
  - Existing ISO/RTO aggregation programs in have improved DR responsiveness
- Concerns for disallowing the DR opt-out:
  - Questionable DR performance during periods of system strain
  - Are DR aggregation programs providing cost-effective reliability benefits?
  - Could disrupt established statutory & regulatory regimes of states utilizing opt-out

Potential Regulatory Implications for the Missouri PSC

Potential Regulatory Implications for the Missouri PSC



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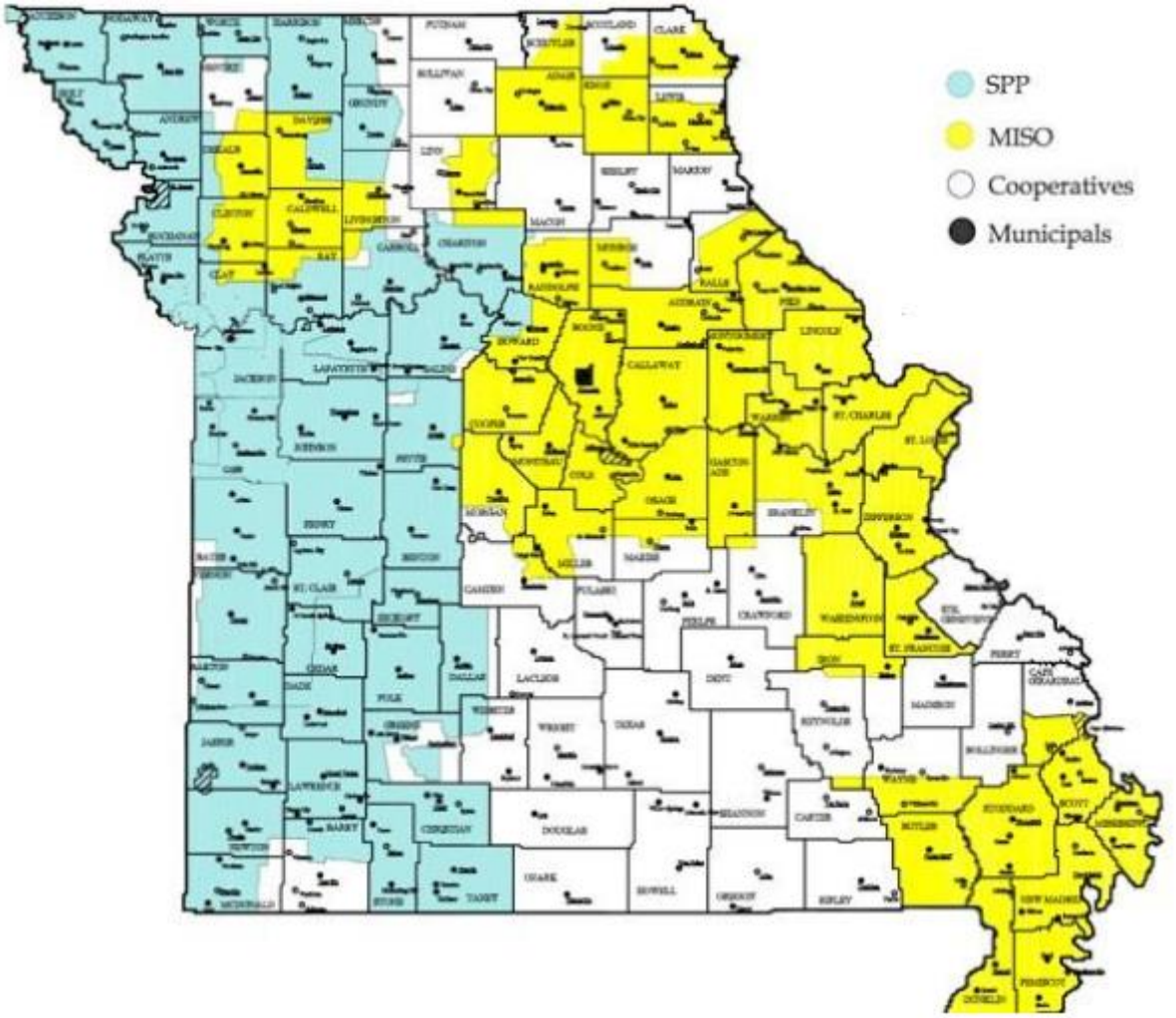

Source: MPSC (August 2014)

Potential Regulatory Implications for the Missouri PSC

- Order 2222-A demonstrates that FERC is confirming:
  - It has the authority over DERs participating in wholesale markets
  - RERRAs have authority over coordinating DER participation with the RTOs
- As a state currently utilizing DR opt-out (Order 719), the Missouri PSC may wish to examine potential impacts to the state's statutory and regulatory regimes
- The Missouri PSC may also wish to participate in the NOI request for information, so that its experiences are represented in the proceeding

Potential Regulatory Implications for the Missouri PSC

ISO/RTO Actions (Opportunities for Coordination?)

MISO	• Coordinate with impacted parties will require transparency and communication to ensure system reliability and prevent double counting • Visibility is important…measurement and verification tools will require considerable thought to ensure impacts are understood by system planners and operators (distribution and BES)
SPP	• Examine 14 states (or co-ops within states) to determine net metering approaches • Determine data collection needs, aggregation parameters, and utility/transmission customer outreach plans • Information-sharing with other RTOs

Thank you!

Any Questions?

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Session 4

MISO & SPP Status Update

Timothy Caister, Deputy General Counsel – Regulatory and DER Program Lead, MISO

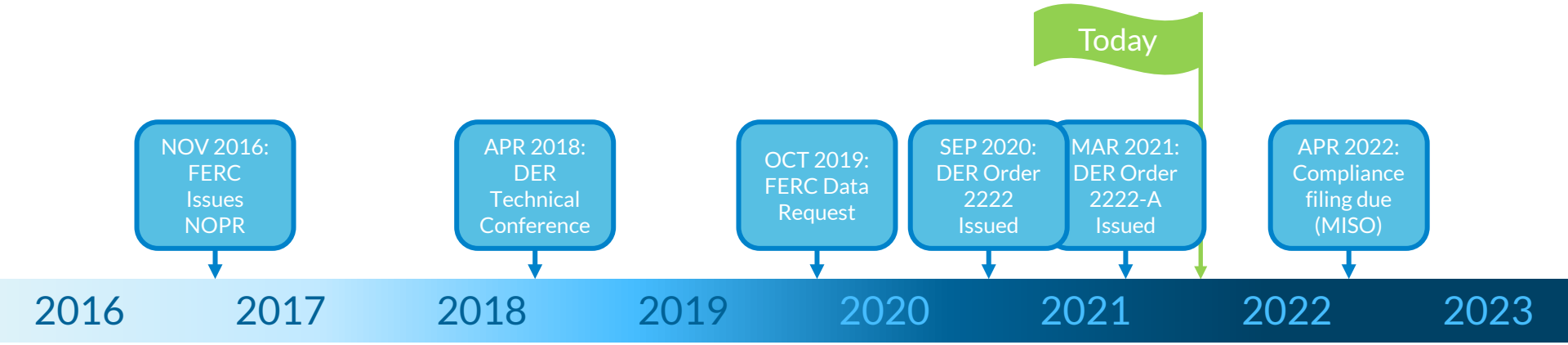
FERC Order 2222 Compliance Plan and Filing Framework

Missouri Public Service Commission

June 29, 2021

Background on FERC Order 2222

FERC Order on DER has seen a long development



"We define a distributed energy resource as any resource located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

O2222, fn. 1; see also P 114

Outline of the FERC Process

- Order No. 2222, issued on September 17, 2020, requires that ISOs/RTOs allow distributed energy resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation of resources.
- Order No. 2222-A, issued on March 18, 2021, modified/clarified certain aspects of Order No. 2222 on rehearing, including removing RERRA opt-out rights for "heterogeneous" DER aggregations.
- To comply, ISO/RTOs either need to:
  - Revise their tariffs consistent with specific requirements from the Order, -OR-
  - Demonstrate how current tariff provisions satisfy the intent and objectives of the Order.
- MISO will need to make substantive tariff edits to comply with this Order, and existing tariff language for market participation, registration, settlement, and more will serve as a guide for the creation of DERA rules.
- FERC did not establish a specific implementation deadline in Order No. 2222; rather, ISOs/RTOs must propose an implementation deadline in the compliance filings.
- This presentation describes the MISO's high-level design approach to comply with Order Nos. 2222 and 2222-A, and design decisions underway to respond to the Order.
- MISO is continuing to receive and reflect on feedback from stakeholders, which may result in design modifications and updates that will be shared with stakeholders.

Order 2222 and 2222-A: High-Level Requirements

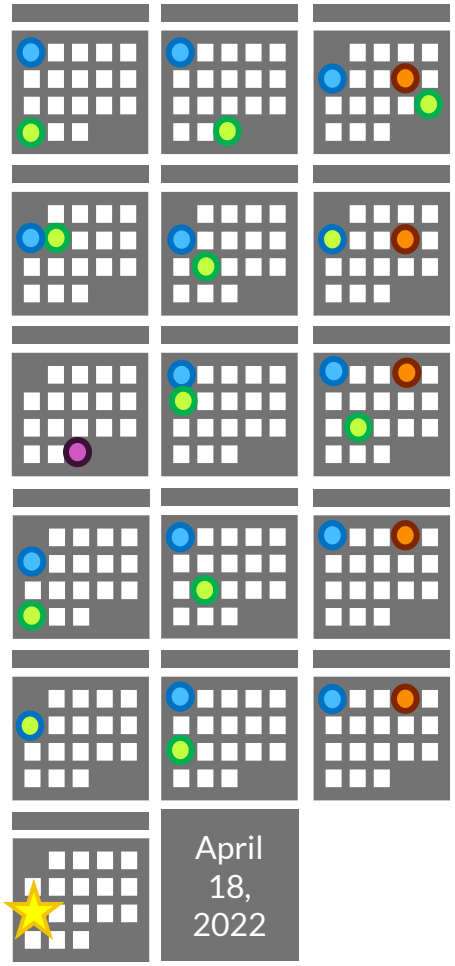
- ISOs are required to change tariffs to accommodate DER aggregations in energy, ancillary services, and capacity markets.
- Aggregations can be one asset, as small as 100kW, and "heterogeneous" (i.e., an aggregation comprised on both demand resources and at least one DER capable of injecting onto the grid).
- ISOs can limit maximum DER resource and/or aggregation size.
- DER aggregations, including qualifying facilities, will be subject to state interconnection requirements rather than the ISO queue process.
- Significant flexibility is allowed for single node aggregation, methods of communication, and maximum size, but ISO choices must be technically explained and not overly burden DER aggregators.
- FERC recommends that each ISO create a "coordination framework" to clarify the communication and other responsibilities of the ISO, Distribution Company, RERRA, and DERA. However, the DERA is ultimately responsible to attest it has met all the requirements for registration.
- In O2222-A, FERC allowed aggregated demand resources to participate in a heterogeneous DER aggregation and not be subject to RERRA opt-out rights.
    - RERRAs retain the right to limit DERA participation to retail markets only.

DER TF O2222 Public File Calendar, Issues, Requirements

MISO filed, and was granted, a Motion for Extension of Time to file our compliance plan with FERC

A	Commission Jurisdiction and General Requirements
B	Definition of DER and DERA
C	Eligibility to Participate in RTO/ISO Markets through a DERA
D	Locational Requirements
E	Distribution Factors and Bidding Parameters
F	Information and Data Requirements
G	Metering and Telemetry Requirements
H	Coordination between the RTO/ISO, Aggregator, and Distribution Utility
I	Modification to List of Resources in Aggregation
J	Market Participation Agreements

- DER Task Force
- Market Subcommittee / Present Design
- Electric Distribution Company Workshop
- FERC Filing



- MISO stakeholders created a Task Force to address DER compliance.
- DER Task Force and DER Distribution Company workshops will continue through extension period.
- 9-month extension calendar allows for additional collaboration.
- **Roles of RERRA, Electric Distribution Company (EDC), DERA, and MISO need to be established.**
- Further details can be found on MISO's DER Task Force website and by joining the mailing list.
- EPRI also has a robust O2222 effort, with participation by RTO/ISO's, utilities, and DER aggregators.

Key Terminology

- DER Glossary will be a living document and a link has been added to the DER pages on the MISO website.

- While the acronyms are similar, MISO has made a distinction between the market participant who is the Aggregator of DER (DERA) and the aggregation of DER (DERa). This is consistent with other similar items in our tariff.

- Triple A data – what does MISO need from data provided by DERAs?
  - Automated – human intervention is not required; signals are automated.
  - Accurate – traceable and auditable.
  - Actionable – data can quickly become overwhelming; what is necessary?

- Distribution Company (DC) vs. Electric Distribution Company (EDC)
  - MISO used the former term when scheduling workshops.
  - In the MISO tariff, EDC is a defined term.
  - EDC will be the term used going forward.

FERC has called for collaboration across jurisdictions and seams; successful implementation requires developing new frameworks

MISO has the Facilitation Role in Order 2222

Relevant Electric Retail Regulatory Authority/ PUC	Transmission Owner (TO)	MISO	Local Balancing Authority (LBA)/ Load Serving Entity (LSE)	Electric Distribution Company (EDC)	DER Aggregator
Review/Approve			Operate		
• Define local interconnection requirements • Assign any cost allocation/ recovery of upgrades • Dispute resolution • Review wholesale market participation eligibility for DERA • Establish small utility opt-in • Supervise applicable integrated resource planning process	• Understand DER flows at EPNode level • Plan reliable trans-mission system • Evaluate trans-mission system upgrades • Coordinate transmission – distribution interface	• Enable participation in all markets • Model, recognize, and value impacts on transmission system • Maintain reliability on transmission system • Coordinate with DERA, EDC, TO and RERRA • Dispute resolution	• Manage day-to-day system operations • Represent the EDCs in the DERa enrollment review	• Evaluate DER flows and impacts on distribution systems' reliability • Coordinate T&D interface • Manage DER interconnection • Coordinate communication with DERA and RTO • Review DERa enrollment compatibility	• Register with the ISO, providing required data on DER location, configuration, telemetry, and performance capability • Participate in wholesale market based on applicable wholesale and retail rules • Coordinate communication with RTO and EDC

Key Requirements of FERC 2222: Section A. FERC Jurisdiction

1. FERC jurisdiction
   - DERA becomes FERC jurisdictional utility
   - Distribution utilities can assess wholesale distribution charges on DERA
2. Opt-out/ in
   - MISO must accept bids from DERA:
     - If utility >4 million MWh sales in prior fiscal year
     - If utility ≤ 4 million MWh sales in prior fiscal year, but only with RERRA approval
   - O2222-A removed RERRA opt-out rights for demand resources participating in a heterogeneous DERA
3. Interconnection

- FERC declined to exercise jurisdiction over DER interconnection to distribution
  - FERC may revisit need to assert DER interconnection authority if process used as a barrier to entry
- MISO/ EDC/ TO coordination needed to share information to study impact of aggregation on the transmission system

Legal citations O2222 P 42, P 62, P 65, P 90, P 96, P 99, P 101; O2222-A P 22-23, P 28

RTOs' Current Work on Order 2222 Compliance (MISO DERTF / SPP 2222TF)

Guiding Principles will be used to evaluate potential solutions

MISO and the DERTF should :

1) Identify DER-related issues with existing markets, tools and processes to ensure continued reliable and efficient operations.
2) Establish and support collaboration and coordination frameworks with stakeholders, including distribution utilities, to ensure awareness of opportunities and challenges, to ensure distribution entities can maintain reliability, maintain compliance with RERRA requirements, to ensure awareness of opportunities and challenges, and to facilitate technical coordination, policy conversation and education.
3) Address any DER-related issues and barriers impacting such resources' participation in MISO's wholesale markets with reasonable solutions that enhance or support reliability and market efficiency.
4) Support current and future resource and transmission planning initiatives and goals in concert with MISO's response to the Reliability Imperative, while complying with applicable orders, regulations and jurisdictional requirements.

Evaluation Framework is based on Guiding Principles

Order 2222 Requirement

Must be met in any solution (pass/ fail)

Grid Reliability and Resiliency

Availability, flexibility and visibility

Transmission reliability and rapid recovery from disruption

Visibility and operational awareness

Timely control and flexibility to respond

Availability of resources to respond when needed

Market Efficiency

Efficiently and cost effectively align operations with markets

Minimizes barriers to participation

Ability of market to value benefits of DERs

Solution Complexity

Degree of changes or level of complexity to implement

Ease of coordination among MISO, EDC, RERRA, and DERAs

Implementation Costs

Costs of implementation including time required for all parties

Impacts to other priorities

Interconnection

How should MISO, DERA, and local utilities coordinate interconnections?

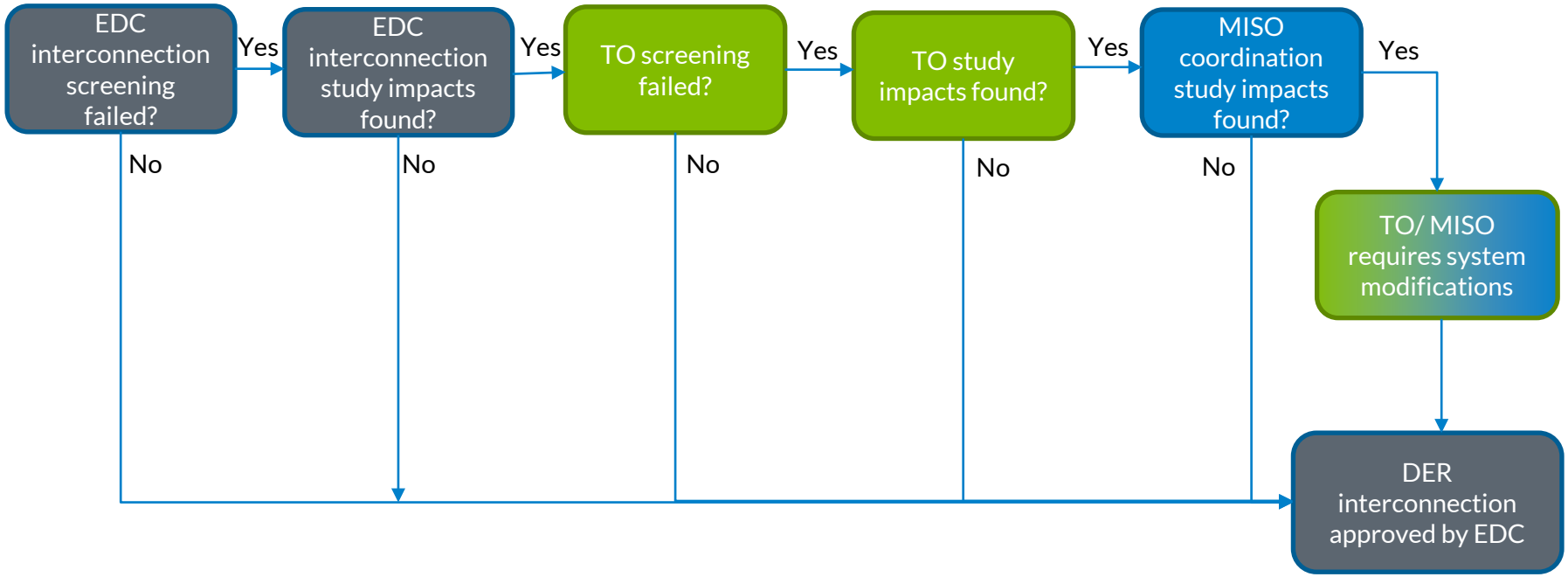
Alternatives Considered

1. How should the coordination be triggered?
    1. Transmission back feed
    2. DER size limit
    3. Utility specific
2. What will be the study process?
    1. Cluster (group study)
    2. Individual requests
3. How will the studies be coordinated with the remainder of the MISO Interconnection Queue?
    1. Request-date based
    2. Study-commencement based

Proposed Principles for DERa Interconnection

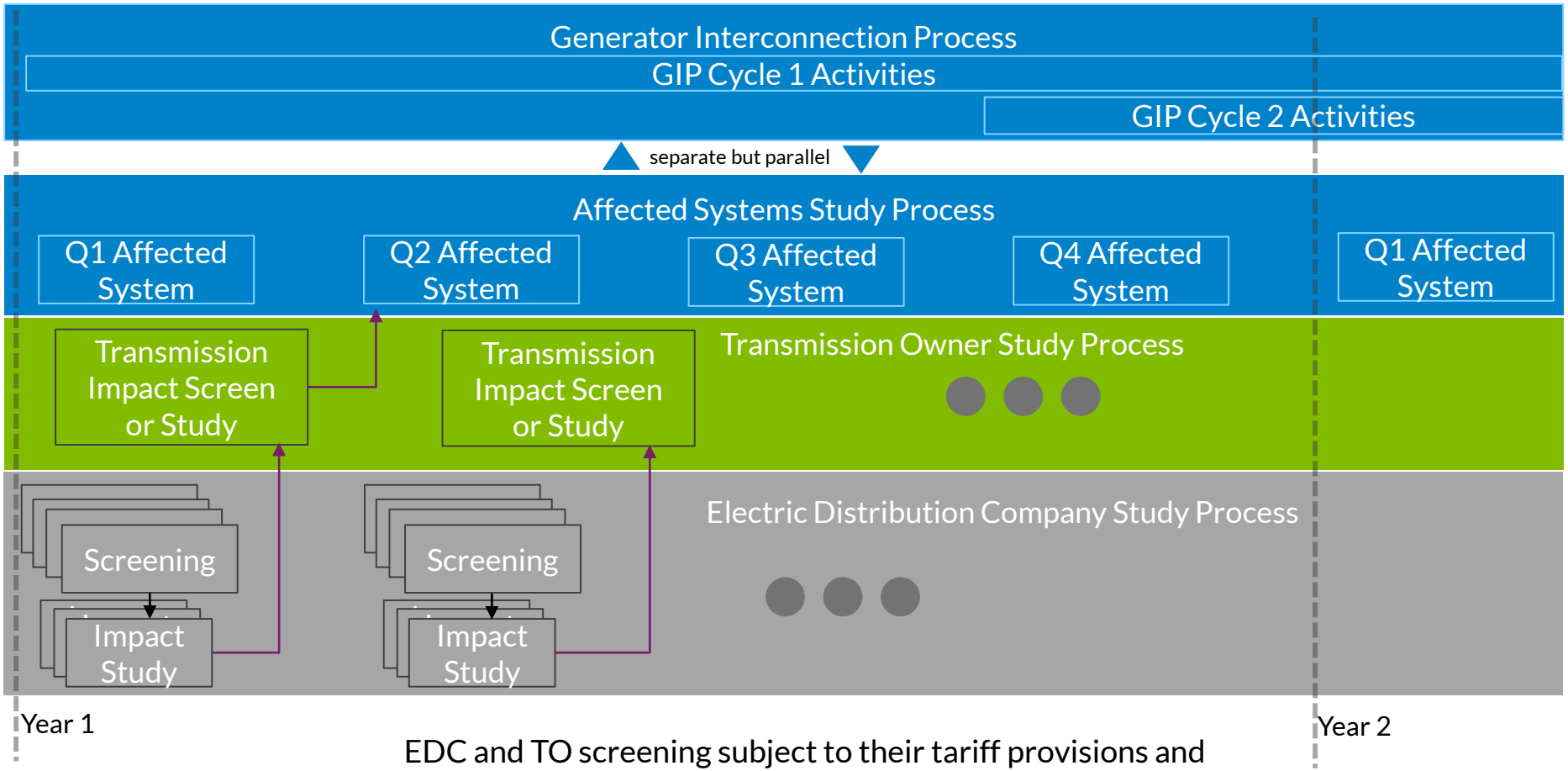
- EDC interconnection approval is a prerequisite for wholesale aggregation registration
- DER or DERa will not enter the MISO queue, but needs to be coordinated:
  - Threshold for affected systems study
  - Timing and frequency of studies
  - Coordinating study assumptions and results

Conceptual Flow of EDC, TO, and MISO Interconnection Evaluation



EDC and TO screening subject to their tariff provisions and RERRA interconnection processes

The Transmission (MISO) and Distribution (state) Processes



EDC and TO screening subject to their tariff provisions and RERRA interconnection processes

RTO Participation, Locational, Bidding Requirements

Key Requirements of FERC 2222:
B. Definition of DER and DERA

A "DER" is defined as " 'any resources located on the distribution system, any subsystem thereof or behind a customer meter.' These resources may include, but not limited to, resources that are in front of and behind the customer meter (e.g., customer sites capable of demand reduction), electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment." *O2222, P 114*

A "DER Aggregator" (DERA) is defined as "an entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of RTO/ISOs." *O2222, P 118*

An "Injecting DER" will be defined by MISO as a DER participating in wholesale markets as part of a DERa and is a source of generated or stored energy that is metered and settled as if injecting energy rather than as reducing the customers metered load. *See also "net injection" and issues of double counting.*

Participation Models, Locational Requirements, and Bidding Parameters: Decision Summary

Question	Status
How would existing resource types have to be changed to represent the range of DER aggregation's characteristics?	Complete - March MSC
What is the broadest, technically feasible scope for DER aggregation?	Complete - March MSC
How should Market Systems address small resource size in optimization engines to not lose resolution?	June MSC
Should there be a limit on DERa size?	June MSC
Should large DER assets be required to participate in markets individually?	June MSC
How should DERs be modeled in reliability, market, and planning models?	Under discussion
How can DER be aggregated in MISO's capacity construct?	Target July RASC
How should heterogeneous aggregations of DER be accredited for capacity?	
Are there process improvements which could allow interim participation of DERa prior to full software enhancements?	DER TF Q4 2021

Key Requirements of FERC 2222: Section C: Eligibility to Participate

- Allow DER aggregation market participation under one or more participation models
- Allow heterogeneous DER aggregation
  - Aggregator is responsible to meet performance and registration requirements
- Allow dual participation even if DER is in retail programs
  - Allows narrowly designed restrictions to prevent double payment
  - RERRAs allowed to limit DER participation to retail markets only
- 100 kW minimum size requirement for DERa
  - Allows for a maximum size or requires explanation why a maximum DERa size is not needed
- Requires a maximum size for individual DERs within an aggregation or an explanation why no such limit is needed
  - Sets no minimum size requirement for individual DER
- Single Resource aggregation is allowed under the Order

Legal citations O2222 P 61, P 129, P 130, P 142, P 160, P 162, P 179, P 180, P 185, P 186

Key Requirements of FERC 2222 : Locational Requirements, Distribution Factors, and Bidding Parameters

Section D: Locational Requirements

- Establish locational requirements that are as geographically broad as they are technically feasible.

Section E: Distribution Factors and Bidding Parameters

- Addresses bidding requirements to represent physical and operational characteristics.
- If multi-node aggregations are allowed, require distribution factors.

Legal citations O2222 P 204, P 225

How would existing resource types have to be changed to represent the range of DER aggregations' characteristics?

Alternatives Considered

1. **DIRs and ESRs at 0.1 MW for DER**
2. DIR, ESR, GEN and DRR II at 0.1 MW
3. DRR I, DRR II, ESR at 0.1 MW. DRR I are only multi-node
4. All resources changed to 0.1 MW. DRR I are only multi-node

March DER TF Agenda Item 5
April DER TF Agenda Item 4b
May DER TF Agenda Item 3a

ESR: Energy Storage Resource
DIR: Dispatchable Intermittent Resources
GEN: Generation Resource
DRR: Demand Response Resource

How would existing resource types have to be changed to represent the range of DER aggregations' characteristics?

DIRs and ESRs at 0.1 MW for DER

Benefits

Grid Reliability and Resiliency

Current offer parameters in the ESR and DIR participation models can cover the range of characteristics needed to represent DERas.

Market Efficiency

Options allow DERas to match participation with the characteristics of their resources.

Minimize Implementation Costs

Leveraging MISO's DIR and ESR models allows DERas to participate in MISO's markets, with minimal software costs.

Minimize Complexity

Rather than creating a new model, leveraging other MISO models reduces complexity in resource options.

Considerations

Grid Reliability and Resiliency

Uncertainties with mapping DERa to a single node within distribution system.

Market Efficiency

ESR Capability -Based Resource types must self-commit. If all capabilities are not captured, the system could lose efficiencies.

Minimize Implementation Costs

Introducing new resource types adds substantial cost and time considerations.

Minimize Complexity

Modifying / introducing resource types adds complexity to solutions. Additional complexity for load modifying DERa on distribution.

Assumptions

1. Resource type must accommodate DERa as small as 0.1 MW.
2. DERs can participate under existing resource types at existing size and location constraints if they qualify.

Risks

1. DERa implementation is impacted with delays in MSE and ESR.
2. Relies on aggregation at a single EPNode to function within MISO market systems.
3. Limited operation experience with 0.1 MW resources. No MISO or Market Participant experience with ESR.

What is the broadest, technically feasible scope for DER aggregation?

Alternatives Considered

1. **Single EPNode for DER aggregation participation.**

2. Single EPNode for dispatchable resources; multi-EPNode for on/off resources.

3. Clusters of EPNodes created based on historical mapping for continuously dispatchable resources.

4. Single EPNode for continuously dispatchable resources; multi-node aggregation allowed for on/off resources in same Local Balancing Authority (LBA).

March DER TF Agenda Item 5
April DER TF Agenda Item 4c

What is the broadest, technically feasible scope for DER Aggregation?

Single EPNode for DER aggregation participation

Benefits

Grid Reliability and Resiliency

EPNode level provides needed visibility and operation awareness at the right locations on grid.

Market Efficiency

Provides transparent locational pricing and aligns with efficient operational needs. 100kw minimum size increases potential participation.

Minimize Implementation Costs

Costs are minimized by minimizing changes to the market engines.

Minimize Complexity

No market clearing changes needed to accommodate EPNode dispatch of DERa.

Considerations

Grid Reliability and Resiliency

Timely and accurate distribution factors may be infeasible given the dynamic distribution system and DERa locations.

Market Efficiency

Multi-node aggregations would result in inefficiencies where resources hurting a constraint are paid the same as those helping.

Minimize Implementation Costs

Substantial system changes, including modeling, clearing, dispatch, and settlement, are required for multi-node aggregations.

Minimize Complexity

Communications complexity would be increased due to needed real-time updates to distribution factors.

Assumptions

1. DERs could use existing DRR 1 model at 1 MW aggregation size.
2. Research studies show broad multi-node aggregations can lead to reliability concerns and power/ price oscillations that are worsened with inaccurate distribution factors.
3. Current and MSE systems will not alleviate these concerns.

Risks

1. Limiting to a single EPNode may limit participation due to difficulty in aggregating 100 KW at a single node.
2. There may be errors in mapping aggregations to a single EPNode.

Should large DER assets be required to participate in markets individually?

Alternatives Considered

1. Individual assets above 5 MW and desiring to participate in Bulk market should be represented individually and not in a DERa.

2. Individual assets above 20 MW and desiring to participate in Bulk market should be represented individually and not in a DERa.

3. **No individual resource maximum size limitation for participation within an aggregation. Defer to Electric Distribution Companies (EDCs), states, and MISO interconnection studies (if applicable) to identify system impacts or limits due to size.**

April DER TF Agenda Item 4c
May DER TF Agenda Item 3b

Should large DER assets be required to participate in markets individually?

No individual resource maximum size limitation for participation within an aggregation

Benefits

Grid Reliability and Resiliency

Dispatch of DERa at a single EPNode can provide adequate reliability even with large embedded resource.

Market Efficiency

The 'No max size limit' could encourage more participation including Demand Response.

Minimize Implementation Costs

Reduces barrier to participation as compared to increased cost of managing more DERas.

Minimize Complexity

Reduce the number of DERas to manage.

Considerations

Grid Reliability and Resiliency

Imbedding large single resource in a larger aggregation may lose some visibility.

Market Efficiency

Splitting out large DER from DERa may result in fewer small resource to participate in a 0.1 MW aggregation.

Minimize Implementation Costs

None noted.

Minimize Complexity

Requires coordination around EDC and State limits.

Assumptions

1. ISO will limit DERa aggregation range to a single EPNode.
2. NERC SPIDER (System Planning Impacts from Distributed Energy) DER modeling will address visibility requirements.
3. Individual DER has obtained interconnection rights to distribution through EDC and through MISO processes to be defined.

Risks

1. If no individual resource size limit and EDC/ MISO interconnection and participation studies are not detailed, it may mask large resource potential to impact bulk system.
2. If large resources are not individually modeled, then reliability studies may miss impacts of loss of larger resource.

How will DERa be represented in Markets, Operations, & Planning Models?

Alternatives Considered

1. **Representative aggregate generator which can have a positive or negative capability. Maintain current representation of the Transmission / Distribution (T/D) interface. A new DERa market resource model will be created based on ESR and DIR constructs with a single EPNode/ CPNode designation.**
2. Representative aggregate generator which can have a positive or negative capability. Utilize current market resource models and update to represent 0.1 MW minimum with a single EPNode/ CPNode designation.
3. Representative aggregate generator which can have a positive or negative capability. Allows multiple EPNode to single CPNode representation.
4. Create a new DER Aggregation Load Type. Create a new market Load product base on DRR Type I construct.

How will DERa be represented in Markets, Operations, & Planning Models?

Representative aggregate generator ; create separate DER Aggregation Market Resource Type(s). (Single EPNode/CPNode)

Benefits

Grid Reliability and Resiliency

Enhanced operational awareness due to visibility of available resources. Clear designation within models.

Market Efficiency

Allows for inclusion and dispatch of DERA's assets in the MISO marketplace.

Minimize Implementation Costs

0.1 MW dispatch coming with ESR product.

Minimize Complexity

Generator representation aligns with current DIR and ESR resources. Separate product tracked through systems. Clear segregation.

Considerations

Grid Reliability and Resiliency

Analysis of appropriate representative injection point(s) to the transmission system will involve coordination with EDC, TO, MISO, and DERA.

Market Efficiency

If all locational capabilities are not accurately captured, the system could lose efficiencies.

Minimize Implementation Costs

MISO Market current resource dispatch methodology maintained. New product development cost.

Minimize Complexity

MISO Market does not dispatch loads to balance the system.

Assumptions

1. DIRs and ESRs at 0.1 MW for DER and single EPNode.
2. Strive for consistency of representation across planning, operations, and market models.
3. DERA will provide aggregate resource information to MISO for planning, operations, and markets, including real-time and forecast data.

Risks

1. Incorrect identification of electrical impact representation at the Transmission/ Distribution interface.
2. Coordination with vendor to implement new products may create time constraints.

Telemetry and Data Requirements

Key Requirements of FERC 2222: Potential EDC Roles

Section G: Metering and Telemetry System Requirements

"Each RTOs'/ISOs' proposed metering/telemetry requirements should rely on meter/telemetry data obtained through compliance with distribution utility or local regulatory authority metering system requirements whenever possible for settlement and auditing purposes. "

Legal citation O2222 P 269

"To the extent that RTO/ISO proposes that such information (i.e., metering/telemetry data) come from distribution utilities, RTOs/ISOs is required to coordinate with distribution utilities and RERRAs to establish protocols for sharing metering and telemetry data. Such protocols must minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity."

Legal citation O2222 P 270

"To the extent that metering and telemetry data comes from distribution utilities, RTOs/ISOs are required to coordinate with distribution utilities and the RERRAs to establish protocols for sharing metering and telemetry data that minimize costs and other burdens and address concerns raised with respect to customer privacy and cybersecurity. "

Legal citation O2222 P 324

Key Requirements of FERC 2222: Telemetry

Section G: Metering and Telemetry System Requirements

". . . establish market rules that address metering and telemetry hardware and software requirements necessary for distributed energy resource aggregations to participate in RTO/ISO markets."

Legal citation O2222 P 262

"Each RTO/ISO should explain, …. whether the proposed requirements are similar to requirements already in existence for other resources and steps contemplated to avoid imposing unnecessarily burdensome costs on the DER aggregators and individual resources in DER aggregations that may create an undue barrier to their participation in RTO/ISO markets. "

Legal citation O2222 P 264

Information, Metering, and Telemetry Decision Summary

Question	Status
What is necessary to track performance of DERs and DER aggregations?	Under discussion today
How should Demand Response in aggregations be represented to accommodate the 719/745 settlement?	Under discussion today
What needs to be tracked for dual participation in retail and wholesale markets?	Under discussion today
How often is data required via telemetry to support DERa in operations and settlements?	Under discussion today
What technologies for DERa telemetry can MISO accept for market operations?	Under discussion today
What physical and operational aggregate data is needed for registering a new aggregation?	Target August 9 DER EDC workshop

Information and Data – EDC/MISO Coordination, 2021-05-18
Current Metering & Future Considerations – EDC/MISO Coordination, 2021-05-18
Telemetry Considerations - EDC/MISO Coordination, 2021-05-18
Metering and Telemetry Themes O2222 Section G – DER Task Force, 2021-04-12
Review Metering and Telemetry – EDC/MISO Coordination, 2021-03-19
Michigan PSC State Perspective on Metering and Data Access – EDC/MISO Coordination, 2021-03-19

What data needs to be provided to support Operations and Settlements?

Areas to include:

MISO plans to align data needed in these 5 categories:

- Registration/enrollment – location, resource type, static data
- Modeling – based on other requirements
- Resource Offer/Bidding Parameters – based on products provided
- Telemetry – based on products provided
- Metering – see more detailed questions

Information and Data – EDC/MISO Coordination, 2021-05-18

Information and Data Requirements – DER Task Force, 2021-05-10

Meter data is basis for tracking performance: Current practice

Telemetered generation resources submit meter data via MISO Portal

- Meter and telemetry data used to verify performance

Aggregators of Retail Customers (ARC) and Demand Response Resource Type I (DRR-I) submit meter data via the Demand Response Tool

ARC process in Demand Response Tool

- Non-telemetered resources in homogeneous aggregations
- Individual resource measurements rolled up to aggregate value
- Measurement and Verification (M&V) performed at aggregate level to determine performance
- LSE reviews ARC-submitted data
- MISO auditable

What is necessary to track performance of DERs and DER aggregations in settlements?

Alternatives Under Consideration

1. Create new ARC-like process for DERA to submit aggregated meter data broken out by injection, withdrawal, and demand response.

2. Create new ARC-like process for DERA to submit individual DER meter data and MISO will perform aggregation and break out.

3. Enhance ARC process to include heterogeneous DER aggregations.

Current Metering & Future Considerations – EDC/MISO Coordination, 2021-05-18

How should Demand Response in aggregations be represented to accommodate 719/745 settlement?

Alternatives Considered

1. **Demand Response portion of the meter data reported by the DERA will be settled under existing settlement rules developed for FERC Order 745 compliance.**
   - Aligns with existing tools and processes.
   - Addresses double counting by reconstituting load.

Alternative 1 meets all needs; no other alternatives were considered.

20210308 DER TF Item 07 MISO Demand Response and DER Aggregation Current Metering & Future Considerations – EDC/MISO Coordination, 2021-05-18

How might dual participation in retail programs and MISO markets be tracked to prevent double counting?

Alternatives Under Consideration

1. DERA reports only wholesale transactions to MISO.

2. DERA reports only wholesale transactions to MISO. MISO notifies LSE and EDC and makes submitted meter data available for review.

3. DERA coordinates with EDC to utilize existing infrastructure and metering to capture meter data. DERA reports only wholesale transactions to MISO.

4. Use independent data repository to store standardized wholesale and retail transaction data where LSE and EDC can review. DERA reports wholesale transactions from repository to MISO.

[Current Metering & Future Considerations – EDC/MISO Coordination, 2021-05-18]

What steps in the registration process might help prevent double counting?

Ideas Under Consideration

1. Establish criteria for dual participation – e.g.:
   - **Always compatible**, such as Retail VAR support and wholesale capacity
   - **Sometimes compatible**, such as time- differentiated energy
   - **Never compatible**, such as interruptible retail rate claimed by the LSE to meet resource adequacy obligation and MISO capacity market
2. Distinguish phases
   - **Registration** – DERA applies to become MP
   - **Enrollment** – DERA provides DER/ location data
   - **Compatibility Check**– EDC review which may include interconnection engineering
   - **Eligibility Review** – RERRA verifies
   - **Meter Data** – DERA submits, EDC reviews

What technologies for telemetry is MISO looking at for DERa in market operations?

Alternatives Under Consideration

For non-regulating resources under 5 MW (conditional on relaxed scan rates):

1. **Require Inter Control Center Protocol (ICCP) via private Wide Area Network (WAN) only (today's practice).**
   - Telemetry is to/ from DER aggregator, not individual DERs.
   - Already set up to exchange real-time operational data.
   - New WAN and ICCP setup can be expensive.
2. **Require XML or API over internet.**
   - Relatively simple technology currently used for dispatch.
   - Might need development effort to translate push data to reliability and market systems.
3. **Require ICCP over internet.**
   - Internet may provide a relatively easier and less expensive option than moving data via WAN.
   - Setting up ICCP can be expensive.

Coordination between Parties

Key Requirements of FERC 2222: H. Coordination (1)

1. **Market rule on coordination**
- ISO/DERA/EDC/TO/RERRA
  - Registration
  - Operations
- No undue barriers

2. **Distribution utilities**
- ISO must allow distribution utilities to review DERs in aggregations at registration and at updates
- Coordinate criteria for acceptable participation
- ISO must share data with distribution utilities to help them review
- 60 days or less for reviews
- Dispute resolution process

Key Requirements of FERC 2222: H. Coordination (2)

3. **Ongoing operational**
- Establish process for operational coordination
- Require DERA to report changes to offer quantity and distribution factors
- Establish coordination protocols
  - Allow distribution utility overrides of dispatch
  - Establish non-performance penalties

4. **RERRA**
- Role for RERRA in coordinating participation
- Protocols in sharing metering and telemetry data

5. **TO**
- Evaluate impact on transmission system

6. **Coordination Framework**
- Address interoperability of new information technology and communication framework

Next Steps of Interest by RTO on Order 2222

RERRA Meetings

- **Relevant Electric Retail Regulatory Authorities (RERRAs)** may include state public service commissions, public utility commissions, utility boards, municipal authorities, public power agencies, and cooperative boards – any regulatory entity responsible for setting electric retail rates. This term is used throughout Order 2222 and is a typical term in FERC-created documents.

- **July 28 (2-4PM EST)** meeting with RERRAs: This session, open to all, is planned as part of our O2222 coordination framework to speak to the specific concerns of regulators in the MISO footprint as we look at DERA participation in MISO markets. Outside of standard DER TF participation, this meeting, and subsequent RERRA sessions, will be the primary method by which MISO will reach out to RERRAs regarding O2222 coordination. A pre- and post-session survey will be sent to the RERRAs with the opportunity to provide comments on RERRA-coordination needs.

- Future RERRA/MISO sessions are planned for **October 2021 and February 2022**.

DER & Order 2222: Future Sessions

DER Task Force	Distribution Company workshops	Market Subcommittee
June 7 (combined)	June 7 (combined)	June 10
August 2	August 9 (followed by joint Registration workshop)	
August 30	September 13	September 2
October 4	October 11	
November 1*	November 2	
November 29*	No meeting	December 1

- The DER Task Force and Distribution Company workshops are scheduled monthly and will continue until the FERC Order 2222 compliance plan is complete. Future DER TF meetings have been extended, so please update your meeting invites accordingly.
- Concepts and Conceptual Designs will be presented to the Market Subcommittee quarterly.
- Some DER topics will also appear in the Resource Adequacy Subcommittee and the Interconnection Process Working Group. Visit the full calendar posted on the MISO website.

*Not yet added to MISO Stakeholder calendar

MISO is working with other ISOs and groups

- **Electric Power Research Institute** has an Order 2222 program underway
  - Developing use cases to be used by all ISO/RTOs and stakeholders for discussion
  - All ISOs are participating, as well as many utilities
  - Six workstreams; MISO is represented in each
  - Reports are published to the program sponsors
  - Excellent participation from distribution utilities
- **PJM** holds monthly DIRS stakeholder sessions, as well as EDC workshops
  - PJM has received extension
  - Last iteration of proposal elicited significant discussion
- **SPP** holds O2222 meetings approximately 2 times a month
  - SPP has received extension
  - An advisory group makes recommendations to stakeholder committees
- **ISO-NE** has focused their meetings with the NEPOOL Markets committee
  - ISO-NE received extension (2/2/22)
  - Complete proposal to stakeholder community; much discussion
- **Electric System Integration Group (ESIG)** has a DER working group
  - Focused on a longer-term future; not involved intimately with O2222 compliance

Session 4

MISO & SPP Status Update

Michael Dessell, VP, Chief Compliance and Administrative Office, SPP

SPP Southwest Power Pool

ORDER 2222 UPDATE

MICHAEL DESSELLE

VP & CCAO

Helping our members work together to keep the lights on... today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

FERC ORDER 2222 OVERVIEW

ORDER NO. 2222 - PRESCRIPTIVE

- What to Do
  - Allow
  - Establish
  - Address
- What Else to Consider
- What *Not* to do

FERC ORDER 2222 POLICY BUCKETS

1. **Allow** DER aggregations to participate directly in market and establish DER Aggregators as a type of MP
2. **Allow** DER aggregations to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregation
3. **Establish** minimum size requirement for DER aggregations that does not exceed 100 kW
4. **Address** locational requirements for DER aggregations
5. **Address** distribution factors and bidding parameters for DER aggregations
6. **Address** information and data requirements for DER aggregations
7. **Address** metering and telemetry requirements for DER aggregations
8. **Address** coordination between SPP, the DER aggregations, the distribution utility and the relevant electric retail regulatory authority
9. **Address** modifications to the list of resources in a DER aggregation
10. **Address** MP Agreement for DER aggregations

TASK FORCE OVERVIEW

- Limited scope and duration
- SPP staff will provide support through straw proposals
- Frequent meetings

TASK FORCE GOALS

- Enable participation of DER aggregations in SPP's market
- Develop policy and governing document changes necessary to comply with FERC Order 2222
- Approve policy and relevant governing document changes
- Adhere to project schedule to complete work necessary for FERC filing by April, 2022 deadline

FERC ORDER 2222 IMPACT

- Broad impact to SPP
- Task force will coordinate with stakeholder groups as needed
  - MWG
  - SAWG
  - CAWG
  - ORWG
  - RTWG
  - ESR Steering Committee

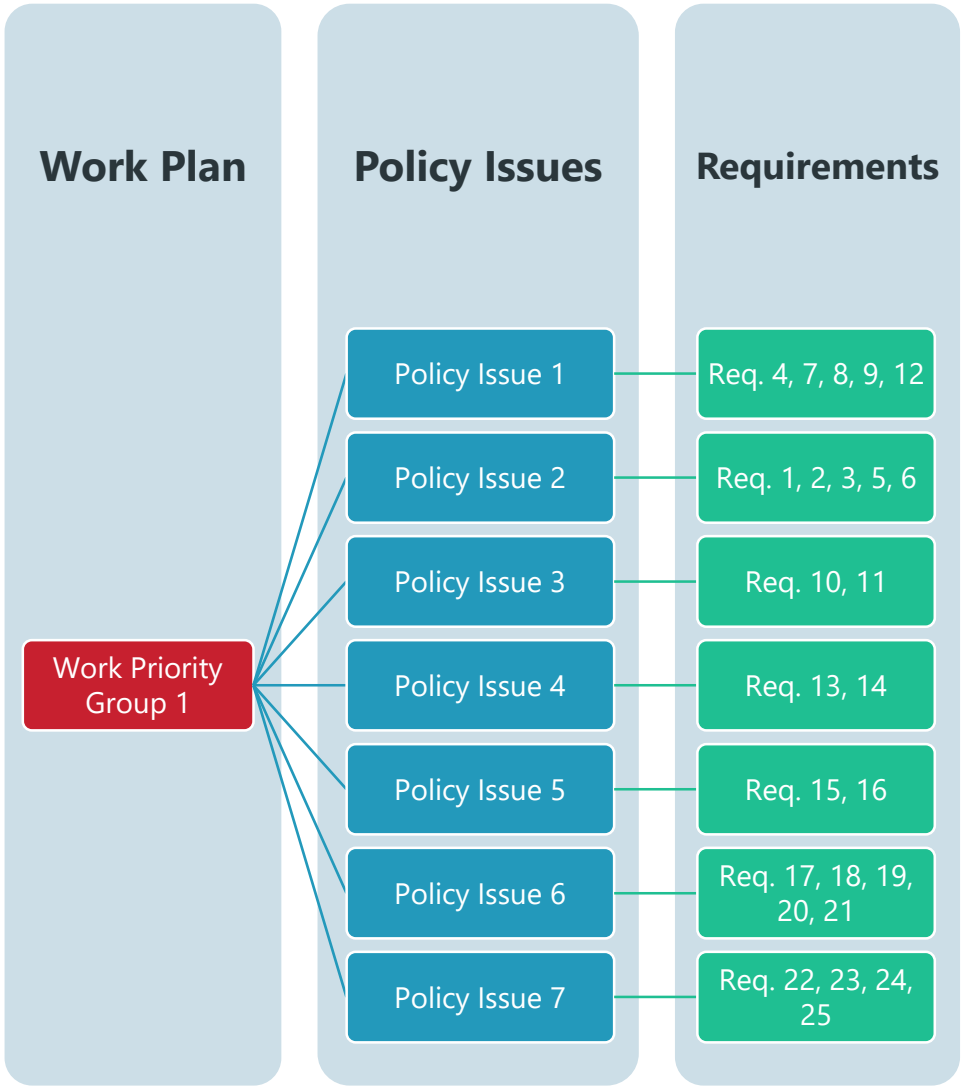
STAKEHOLDER TEAM

Name	Company	Org. Group	Sector
Grant Wilkerson (Chair)	Evergy	BPWG	IOU
Michael Desselle (Staff Secretary)	Southwest Power Pool	NA	NA
Betsy Beck	Enel Green Power	MOPC	IPP
Bill Grant	Xcel	MOPC/SPC	IOU
David Mindham	EDP Renewables	MOPC	IPP
Holly Smith	Walmart	MOPC	LRC
Jessica Meyer	LES	RTWG	Municipal
Mary Ann Zehr	Tri-State	MOPC	Cooperative
Heather Starnes	Counsel MJMEUC	MOPC	Municipal
Natasha Henderson	Golden Spread	MOPC	Cooperative
Richard Ross	AEP	SPC/MOPC/MWG	IOU
Ron Gunderson	NPPD	ORWG	State Agency
Scott Rupp	MPSC	RSC	NA
Steve Gaw	APA	MC/MOPC	AP/PI
Steve Sanders	WAPA	RTWG	Fed Agency
Ted Thomas	APSC	RSC	NA

WORK PLAN

- Prioritize and group work
  - Phase 1 – Compliance filing
  - Phase 2 – Additional work to support and implement what FERC required
- Identify gaps/additional considerations and prioritize as phase 1 or phase 2
- Key issues will be addressed as work progresses
  - Stakeholder groups will give input as needed

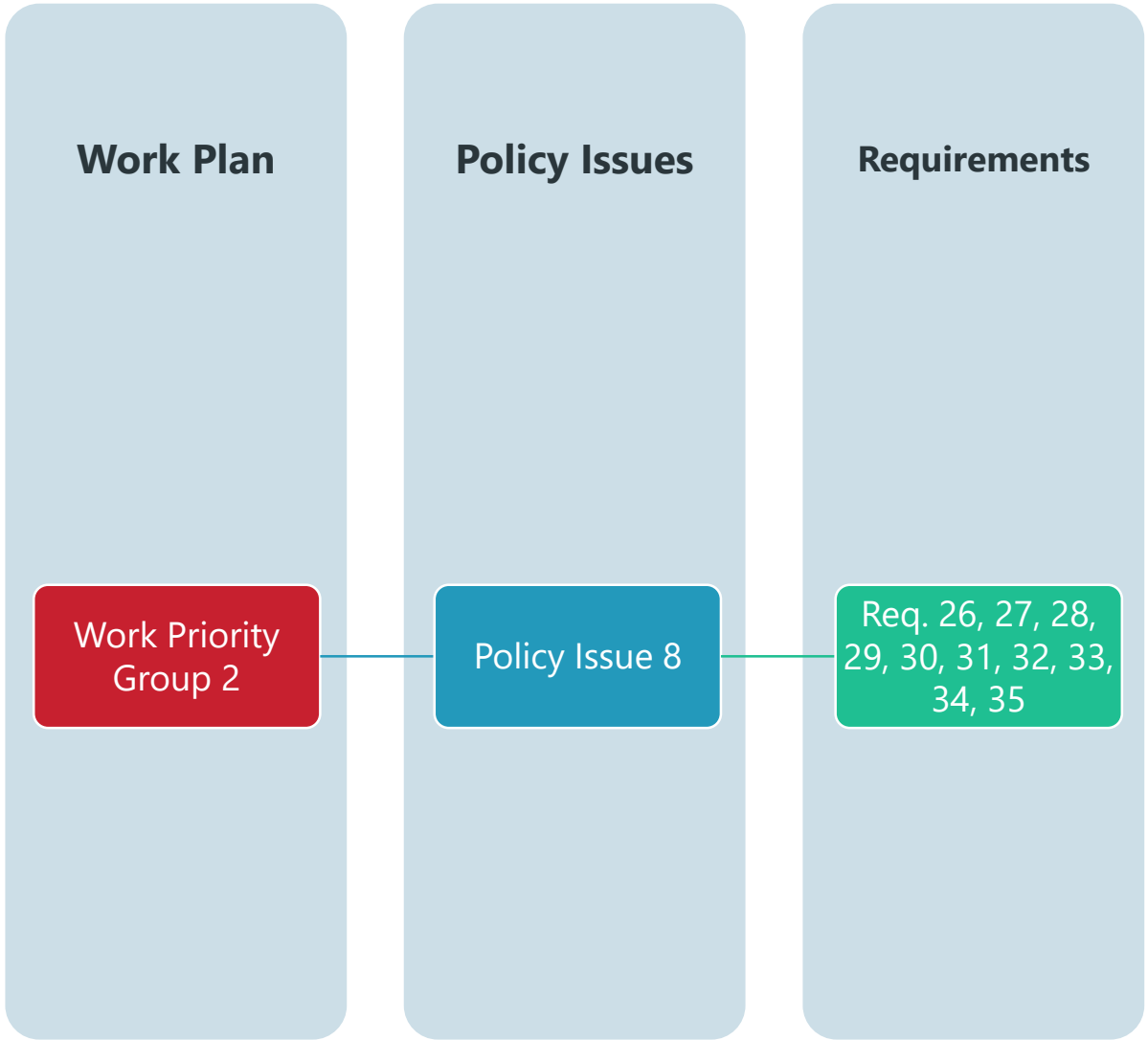
FERC ORDER 2222 WORK PLAN – PRIORITY GROUP 1



Policy Issues

1. Allow DER Aggregations to participate directly in RTO/ISO market and establish DER Aggregators as a type of market participant
2. Allow DER Aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations
3. Establish a minimum size requirement for DER aggregations that does not exceed 100 kW
4. Address locational requirements for DER aggregations
5. Address distribution factors and bidding parameters for DER aggregations
6. Address information and data requirements for DER aggregations
7. Address metering and telemetry requirements for DER aggregations

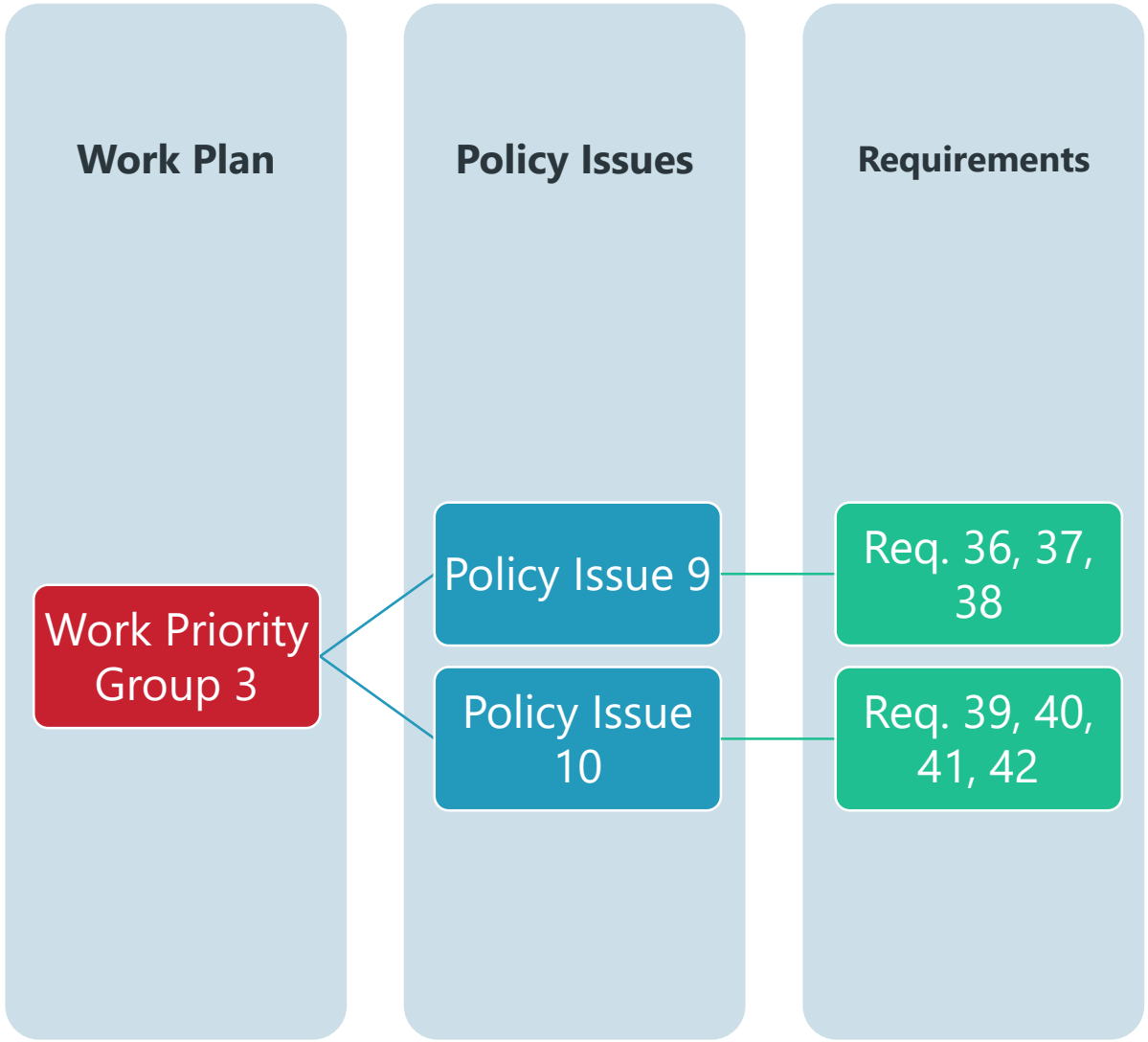
FERC ORDER 2222 WORK PLAN – PRIORITY GROUP 2



Policy Issues

8. Address coordination between the RTO or ISO, the DER Aggregator, the distribution utility, and the relevant electric retail regulatory authorities

FERC ORDER 2222 WORK PLAN – PRIORITY GROUP 3



Policy Issues

9. Address modifications to the list of resources in a DER aggregation
10. Address market participation agreements for DER aggregators

INTERNAL LEADERSHIP TEAM

- Cross-departmental
  - Business leaders
  - Technical subject matter experts
  - Staff secretaries
  - Project management office
- Will not make policy decisions
- Will facilitate task force's work internally
  - Review staff proposals
  - Schedule, milestone, dependency & risk management
  - Make recommendations to task force

PROGRESS REPORT

REVISED TASK FORCE TIMELINE

DATE	TIME	MEETING TOPICS
Tues., Apr 13	1:30 P.M. CST	MOPC meeting
Tues., Apr 20	1:30 P.M. CST	Pos MOPC
Tues., May 11	1:30 P.M. CST	
Tues., Jun 8	1:30 P.M. CST	
Tues., Jul 6	1:30 P.M. CST	
Tues., Aug 3	1:30 P.M. CST	
Tues., Sep 7	1:30 P.M. CST	

DATE	TIME	MEETING TOPICS
Tues., Oct 5	1:30 P.M. CST	
Tues., Nov 2	1:30 P.M. CST	
Tues., Dec 7	1:30 P.M. CST	
Tues., Feb 1	1:30 P.M. CST	
Tues., Mar 8	1:30 P.M. CST	
Tues., Apr 5	1:30 P.M. CST	

Milestones may be added to ensure policy and governing document language is approved in time to obtain executive-level committee approval and draft the filing

DISTRIBUTION UTILITY OUTREACH TIMELINE

DATE	TIME	MEETING TOPICS
~~Tues., May 25~~	~~1:30 P.M. CST~~	
Tues., Jun 22	1:30 P.M. CST	
Tues., Jul 20	1:30 P.M. CST	
Tues., Aug 17	1:30 P.M. CST	
Tues., Sep 21	1:30 P.M. CST	
Tues., Oct 19	1:30 P.M. CST	

DATE	TIME	MEETING TOPICS
Tues., Nov 16	1:30 P.M. CST	
Tues., Jan 25	1:30 P.M. CST	
Tues., Feb 15	1:30 P.M. CST	
Tues., Mar 22	1:30 P.M. CST	
Tues., Apr 5	1:30 P.M. CST	

Milestones may be added to ensure policy and governing document language is approved in time to obtain executive-level committee approval and draft the filing

2222 Dashboard

Policy Issue	Status	# of Req	Percent Complete
1. Allow DER Aggregations to participate directly in RTO/ISO market and establish DER Aggregators as a type of market participant		5	100%
2. Allow DER Aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER		6	67%
3. Establish a minimum size requirement for DER aggregations that does not exceed 100 kW		2	100%
4. Address locational requirements for DER aggregations		1	100%
5. Address distribution factors and bidding parameters for DER aggregations		2	100%
6. Address information and data requirements for DER aggregations		5	55%
7. Address metering and telemetry requirements for DER aggregations		4	26%
8. Address coordination between the RTO or ISO, the DER Aggregator, the distribution utility, and the relevant electric retail regulatory authorities		10	20%
9. Address modifications to the list of resources in a DER aggregation		3	92%
10. Address market participation agreements for DER aggregators		4	100%
Total		42	63%

WORK PRIORITY GROUP 1

COMPLETE:

1. Allow DER Aggregations to participate directly in RTO/ISO market and establish DER Aggregators as a type of market participant
3. Establish a minimum size requirement for DER aggregations that does not exceed 100 kW
4. Address locational requirements for DER aggregations
5. Address distribution factors and bidding parameters for DER aggregations

Open Policy Issues

2. Allow DER Aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations

6. Address information and data requirements for DER aggregations

7. Address coordination between the RTO or ISO, the DER Aggregator, the distribution utility, and the relevant electric retail regulatory authorities

WORK PRIORITY GROUP 2

COMPLETE:

Open Policy Issues

8. Allow DER Aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations

WORK PRIORITY GROUP 3

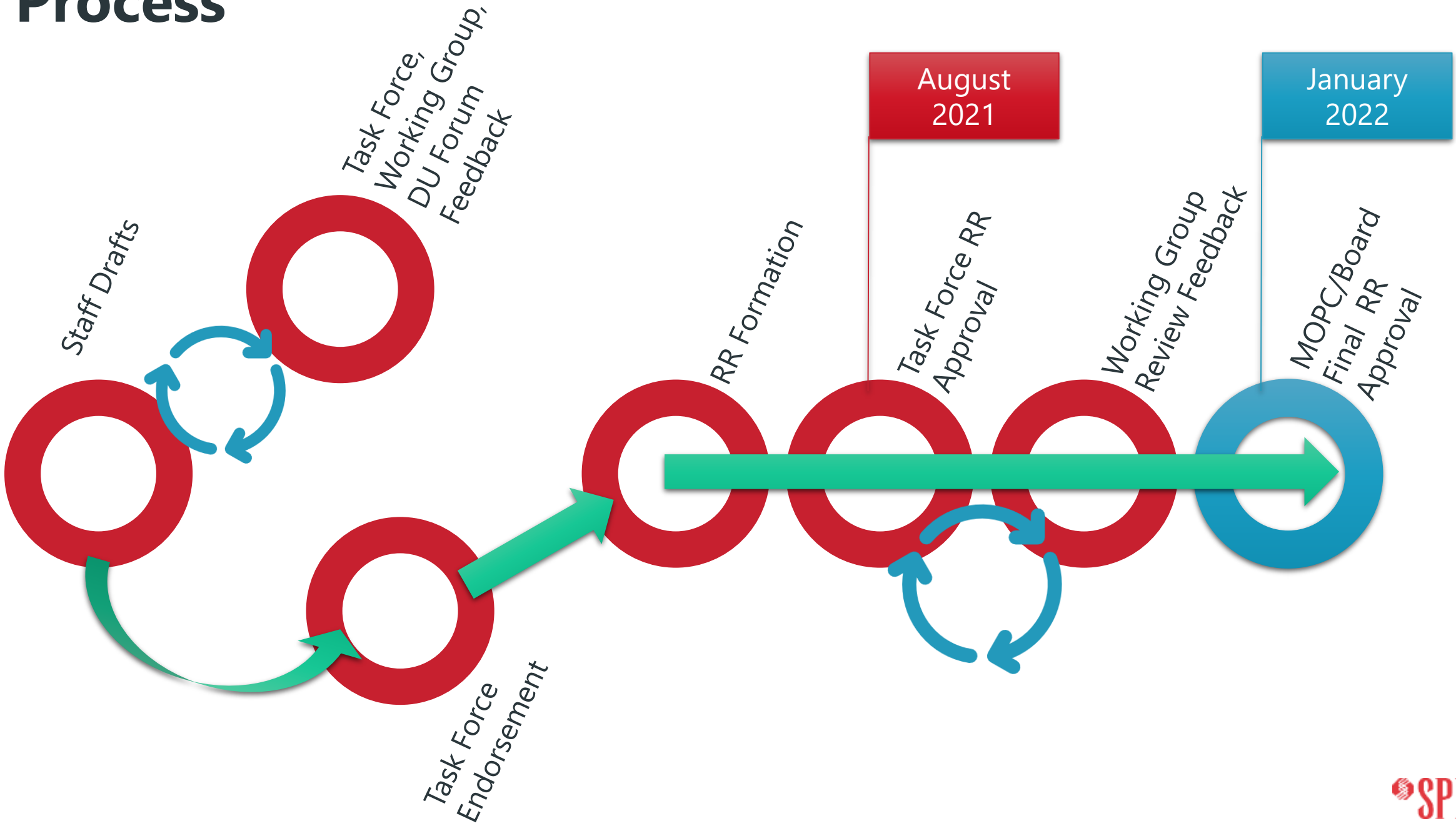
COMPLETE:

10. Address market participation agreements for DER aggregators

Open Policy Issues

9. Address modifications to the list of resources in a DER aggregation

Process


Staff Drafts
Task Force, Working Group, DU Forum Feedback
Task Force Endorsement
RR Formation
August 2021
Task Force RR Approval
Working Group Review Feedback
January 2022
MOPC/Board Final RR Approval

Session 5

Aggregation and Perspective on Demand Response

Frank Lacey, Chair of the Board,
Advanced Energy Management Alliance

Missouri PSC Workshop -- Docket EW-2021-0267

Session 5: Aggregation and Perspective on Demand Response

Frank Lacey

AEMA Board Chairman

June 29, 2021

advanced energy management alliance

AEMA mission and members

Advanced Energy Management Alliance (AEMA) advocates for policies that empower and compensate customers appropriately--to contribute energy or energy-related services or to manage their energy usage--in a manner which contributes to a more efficient, cost-effective, resilient, reliable, and environmentally sustainable grid.

Our members are providers and supporters of distributed energy resources (DERs), including demand response (DR) and advanced energy management, united to overcome barriers to nationwide use of demand-side resources.

AEMA Members

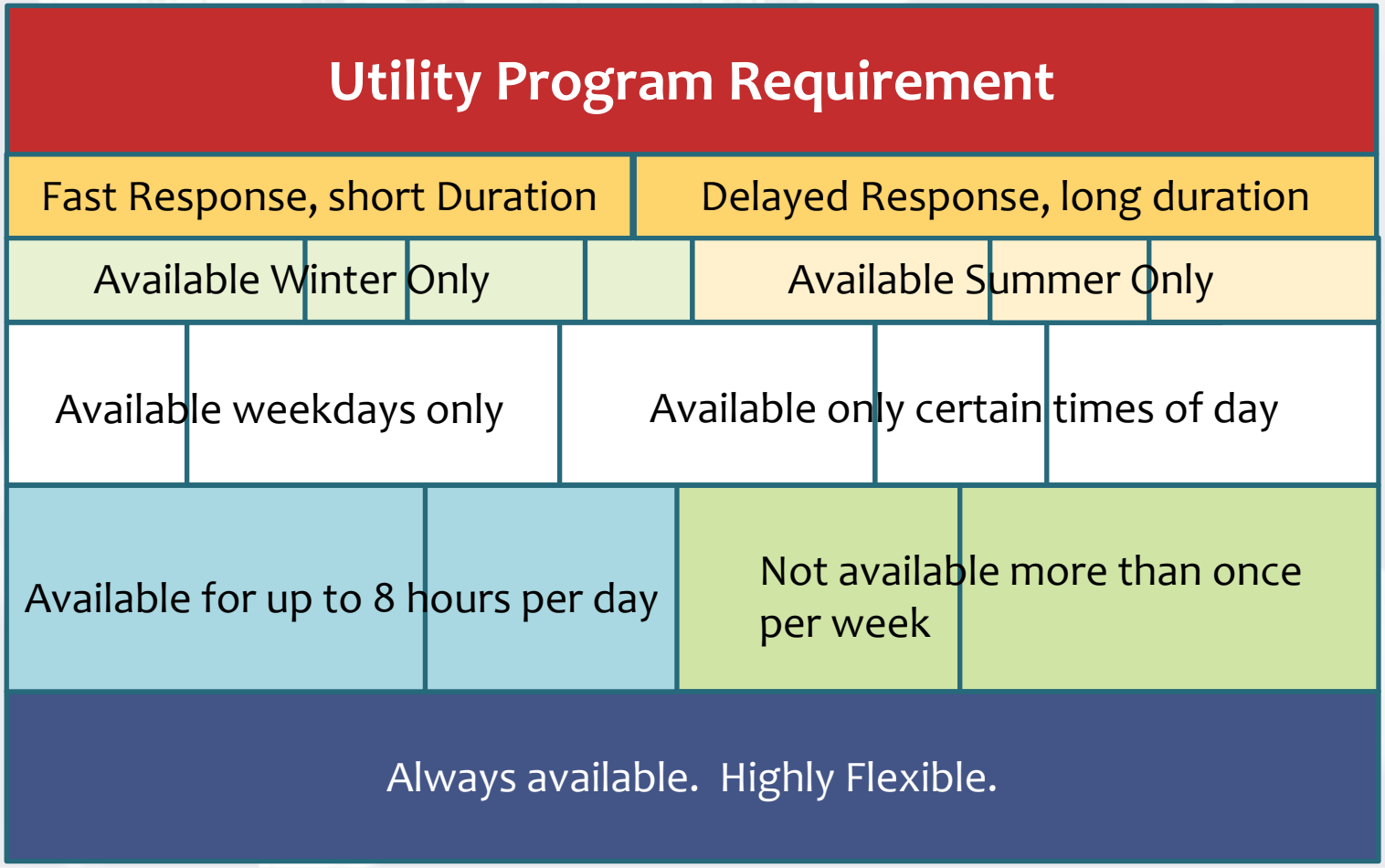
- Aypa
- Centrica Bus. Solutions
- CertainTeed
- CPower
- Demand Power
- Enel X
- EnergyHub
- Google
- Great Circle Solar
- Icetec
- Innoventive Power
- Itron
- Modern Energy
- NRG
- Resideo
- Rodan Energy Solutions
- Uplight
- Viridity Energy
- Voltus
- Walmart
- Law & Consulting Firms
- Other trade associations

DR/DER Products

- Contract
  - Capacity
  - Period-based Reservation Payment
  - Curtailment and/or Delivery on Call of the grid operator
- Economic
  - Economic Based
  - Payment for performance
  - Delivery offered by the load resource

What is Aggregation

- "One size fits all" tariffs do not work for heterogeneous resources



DR/DER Programs

- Utility-based
  - Inflexible, by tariff
- Third-party contracts with Utilities
  - Whose best interest is represented?
- Tariff or market-based
  - Competitive forces seeking customer participation
  - Multiple suppliers building portfolios
  - Portfolio Diversification
  - Risk minimized
  - Reliability and resilience enhanced

DR/DER Compensation

- Payment(s) for Service(s) Provided
  - Capacity products
  - Economic products
- "Double Counting" is not the same as "Dual Participation"
- Potential Services Provided
  - Utility-based Peak load management
  - Utility-based Distribution Relief
  - Utility-based Transmission Relief
  - ISO Programs
- Compensation
  - Each Service Compensated Separately
  - "Capacity" services compensated individually
  - "Economic" services should only be compensated one time

Data Access

- Importance of Customer Data Access
  - Customers and third-party representatives of customers
    - Identifies energy patterns
    - Facilitates opportunities for energy efficiency, DR, and DER
  - Revenue grade Interval data (typically at the hourly level)
  - Data requirements under FERC Order No. 2222 may require increased granularity (5-min) for settlement
- Develop Data Access Standards
  - Standardized rules and systems for sharing of customer data with third parties
  - Customer consent/authorization standards and methods
  - Automated tools to facilitate data sharing
  - Data and cyber-security rules should be developed to protect confidential information – but should not be overly-onerous

Session 5

Aggregation and Perspective on Demand Response

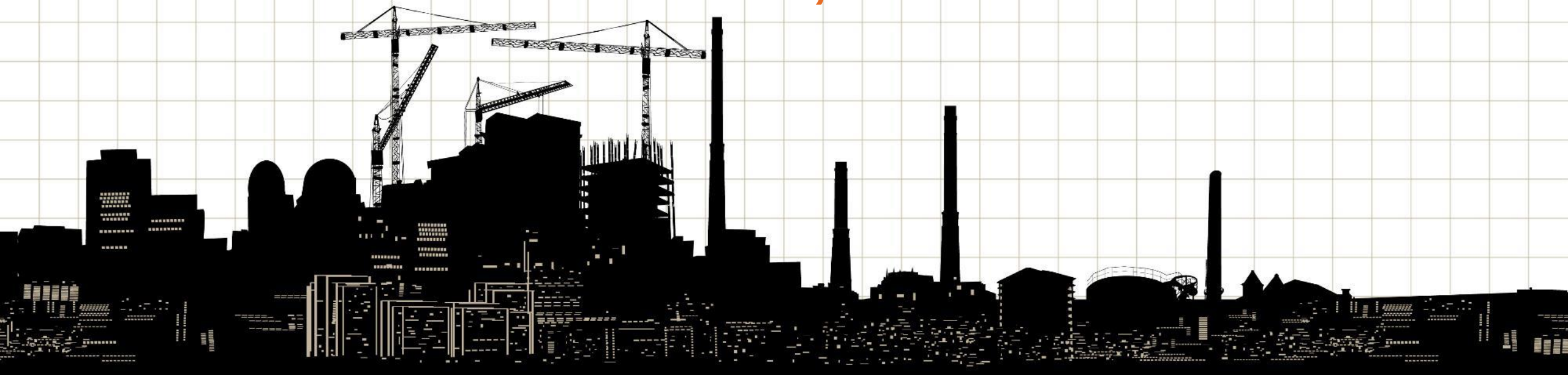
Kenneth Schisler, VP Regulatory Affairs,
CPower Energy Management

The Bridge to Energy's Future

CPower

Missouri PSC Workshop
DR/DER Aggregation

June 29, 2021



About CPower

- 50+ Demand-Side Programs in both regulated and deregulated states.
- 1700+ Customers; 11,000+ Sites
- 4.2 GWs of DERs
- demand response, energy efficiency, distributed generation, energy storage

The Bridge to Energy's Future

CPower

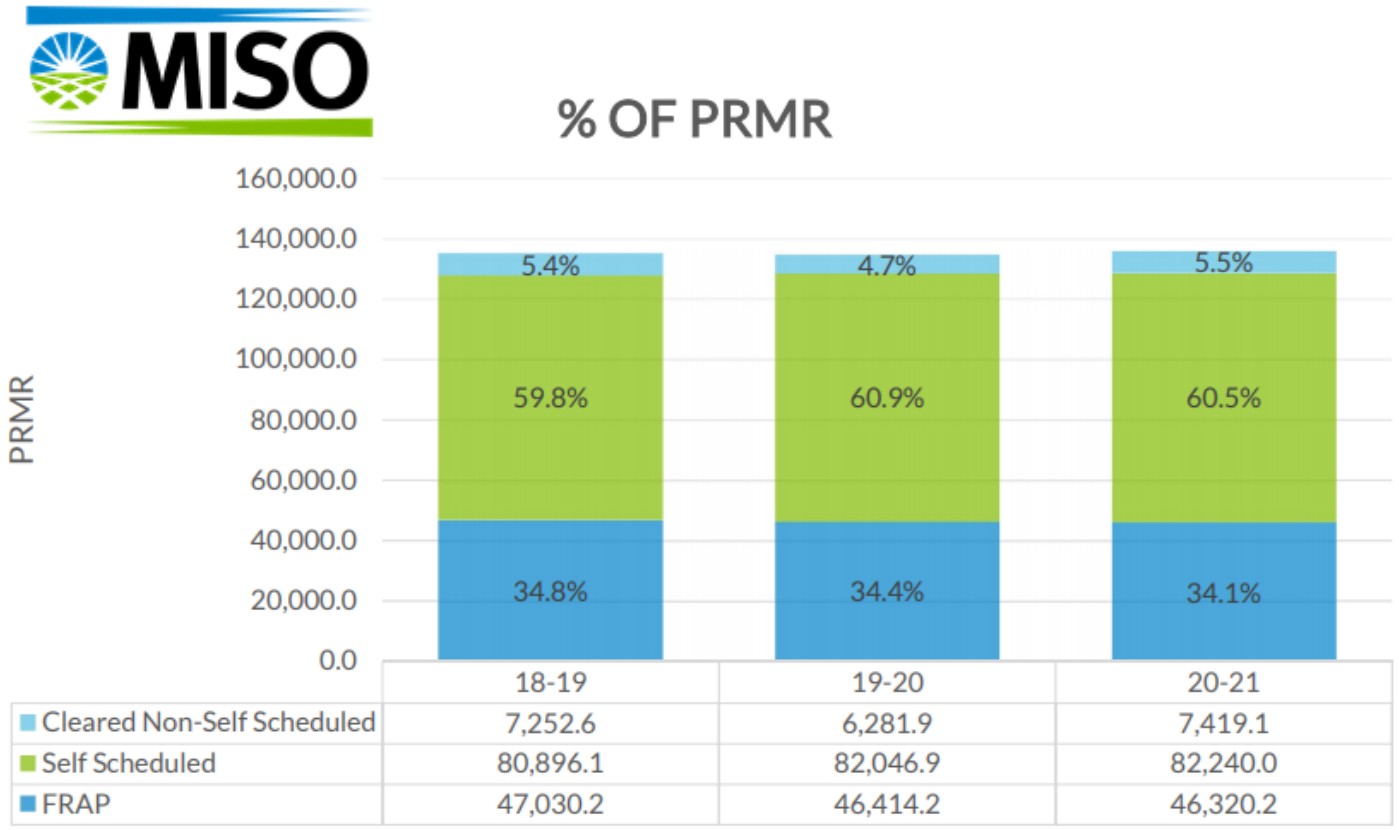
Registry for DR/DER Aggregators

If it chooses to do so, PSC has several jurisdictional hooks to compel participation in DR/DER Aggregator registry . . .

- As a condition of gaining customer-authorized access to customer meter data from utility for DR/DER settlements at MISO.
- As a condition to participate in any utility program or receive a contract to provide resource adequacy credit to a state jurisdictional utility.
- A third option to opt out decision: a conditional opt in. *'DR aggregators are allowed if they agree to [do whatever the commission requires].'*

NY, PA, CA have a registry and regulation covering DR/DER aggregators.*
VA and MD have a registry and limited regulation.*
Most states have no or little regulation over DR/DER aggregators.

DR/DER will remain underdeveloped without utility supply opportunities



	18-19	19-20	20-21
Cleared Non-Self Scheduled	7,252.6	6,281.9	7,419.1
Self Scheduled	80,896.1	82,046.9	82,240.0
FRAP	47,030.2	46,414.2	46,320.2

2020 MISO Resource Adequacy

- **MISO capacity auction accounts for only 5% of the market opportunity.**
- **As a residual market, MISO auction pricing is not reflective of the value of capacity.**
- **~20-30% of the generation component of retail rates represents the value of capacity.**

Utilities subject to state regulation determine counterparties for resource adequacy for 95% of the market.

Consumer Protection in DR/DER

- Necessary where single aggregator vendor with contract flexibility administrator runs the program.
  - Customer's interests may be adverse to DR/DER provider interests, and consumer protection is appropriate where customer lacks recourse or bargaining power.
- Role reversal: Customer is the real 'seller' of DR/DER flexibility, DR/DER aggregator is the 'buyer.'
- Where competition amongst DR providers exists, customers have the upper hand and have options if they don't like the service.
- Concern is lowest among commercial and industrial customers.
- DR/DER participation is not a core utility service, so it is a question of commitment of PSC resources.

Participation Models

Utility DR/DER Rider – Customer terms defined in tariff: hours, dispatches, duration, window, penalties. A program administrator or aggregator may serve as agent to enroll customers.	Maximum control by the utility.
	One size fits all works for too few customers. Underprocurement of available resource.
Program Administrator with Contracting Flexibility - Utility contracts with aggregator for resource. Aggregator contracts with customers to meet commitment.	Can customize contracts to attract more customers.
	Often results in (quite subtle) selective exclusion and aggregator interests adverse to customers.
Multiple Aggregator Procurement – Aggregators compete to provide tranche of DR/DER awarded by utility. Aggregators compete for customers and negotiate terms.	Customer options. Not all eggs in one basket. Customers have power in negotiations for best deal.
	Hard to get market sizing correct. Can be problematic when pricing arrangements are different amongst each aggregator.
Open Enrollment – Utility will contract with qualified aggregators on equal terms. Aggregators compete for customers. May or may not have caps.	Customers have strongest leverage and more technology options and solutions.
	Very small utilities with special/unique requirements may not attract aggregators.

Suggestions for a path forward

- Focus on state issues. DER rule implementation issues at MISO will continue, but the MISO issues are not those most important issues for state commissions.*
- States have enough on their plate with important state issues – 1) customer-authorized data access, 2) models to allow aggregators to support utility resource adequacy plans with DR/DERs, 3) interconnection rules, 4) dual participation, 5) distribution system management with DERs, etc.
- Get started. DR is less complicated than other DERs. Allow ARCs to participate in MISO now with DR, at least with Commercial and Industrial customers, in order to gain experience and understanding of the benefits.

* To be clear, distribution utility capabilities for managing a system with DERs is an important state issue too. Order 2222 is not driving that issue, but rather the rapidly growing deployment of DERs by customers. If anything, DER rule implementation will support distribution system management by giving utilities more information about the activities of DERs participating in MISO's market.

Questions? Thank you!

CPower welcomes the opportunity to offer support and meet with Missouri PSC and staff as well as regulated utilities in the state about best practices for harmonizing wholesale and retail DER participation.

Ken Schisler
Kenneth.Schisler@CPowerEnergyManagement.com
410-725-1462

The Bridge to Energy's Future

CPower

Resources and References

DER/DR Provider Registry

NY DER Regulation and Oversight, https://www3.dps.ny.gov/W/PSCWeb.nsf/All/EAB5A735E908B9FE8525822F0050A299?

NY Uniform Business Practices for Distributed Energy Resource Suppliers, https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/eab5a735e908b9fe8525822f0050a299/$FILE/UBP%20DERS.pdf

PA Conservation Service Providers, https://www.puc.pa.gov/filing-resources/issues-laws-regulations/act-129/conservation-service-providers/

California Demand Response Provider (DRP) Registration Information, https://www.cpuc.ca.gov/General.aspx?id=8314

Substantive provisions found in utility tariffs: Rule 24 Pacific Gas & Electric/Southern California Edison, Rule 32 San Diego Gas & Electric

Virginia Aggregator License/Authorization, https://www.scc.virginia.gov/pages/Competitive-Service-Providers-and-Aggregators

Maryland Curtailment Service Provider Application, https://www.psc.state.md.us/wp-content/uploads/sites/2/Curtailment-Service-Provider-Application.pdf

Dual Participation

NY Commercial Service Relief Program and Distribution Load Relief Program (ConEd), https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/smart-usage-program-guidelines.pdf?la=en

Eversource ConnnectedSolutions (CT, MA, NH), https://www.eversource.com/content/docs/default-source/save-money-energy/curtailment-demand-response.pdf?sfvrsn=8b3bc962_4

Session 5

Aggregation and Perspective on Demand Response

Allison Bates Wannop, Director of Legal and Regulatory Affairs, Voltus, Inc.

voltus

BETTER ENERGY • MORE CASH

Consumer Choice for Aggregation

June 29, 2021

Agenda

- Voltus and our Customer Relationship
- How our Technology Works
- Where and How We Operate
- Demand Response working with Regulators and Utilities in Vertically Integrated States

Introduction to Voltus

Voltus works directly with C&I customers to manage their energy consumption while obtaining payments in the wholesale market

Voltus's DER platform is integrated into every North American wholesale energy market, delivering a real-time "meter to market" platform that automates asset control and financial settlement across electricity markets

Voltus has provided thousands of megawatts of capacity, ancillary services, and energy

Voltus directly participates in MISO and SPP with retail customers in vertically integrated states

BETTER ENERGY, MORE CASH

SIMPLE

NO RISK

NO COST

MORE MARKETS, MORE MEGAWATTS

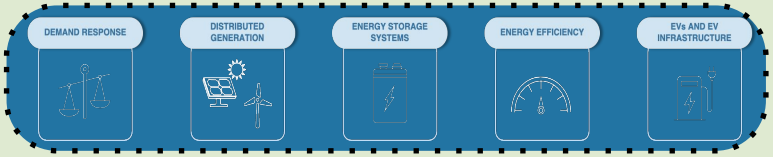
ONE-PAGE COMMERCIAL AGREEMENT

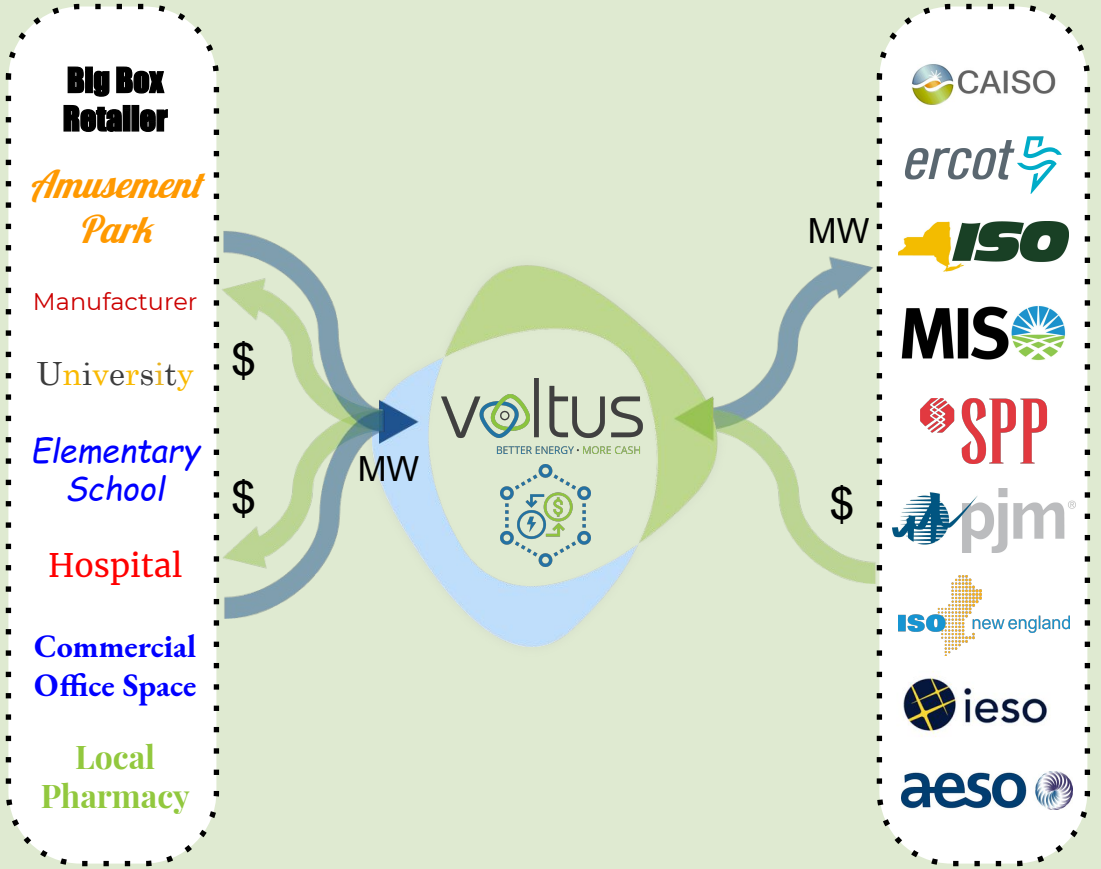
TECHNOLOGY TO MAKE LIFE EASIER

More Markets, More Megawatts

VoltApp is the only distributed energy resource (DER) platform that connects any DER type to any wholesale energy market in North America.

We earn **cash** for a variety of organizations.

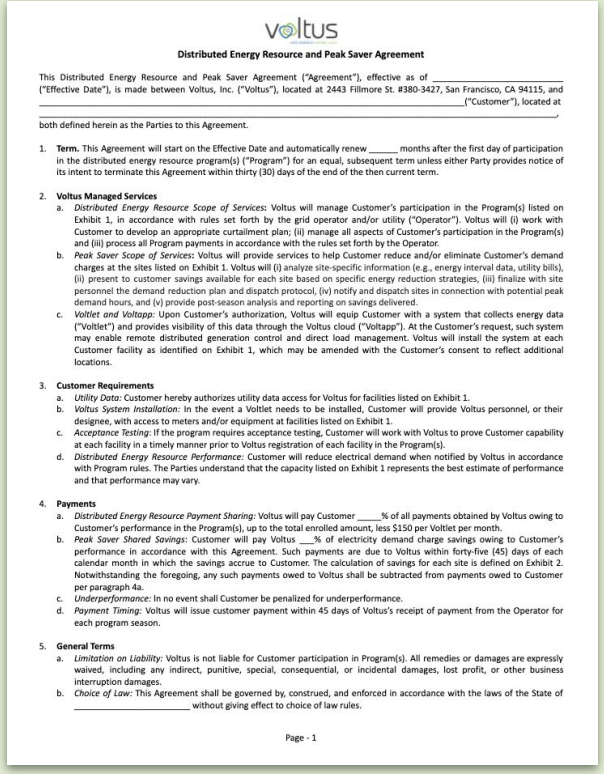




One-page Commercial Agreement

We've turned the complexity of connecting DERs to energy markets into a **simple, single-page agreement**.

We integrate our technology into facilities at **no cost** to the customer, and **we eliminate any risk** to our customers of participating in complex energy markets or utility programs.



voltus

Distributed Energy Resource and Peak Saver Agreement

This Distributed Energy Resource and Peak Saver Agreement ("Agreement"), effective as of _____ ("Effective Date"), is made between Voltus, Inc. ("Voltus"), located at 2443 Fillmore St. #380-3427, San Francisco, CA 94115, and _____("Customer"), located at _____, both defined herein as the Parties to this Agreement.

1. **Term.** This Agreement will start on the Effective Date and automatically renew _____ months after the first day of participation in the distributed energy resource program(s) ("Program") for an equal, subsequent term unless either Party provides notice of its intent to terminate this Agreement within thirty (30) days of the end of the then current term.

2. **Voltus Managed Services**
   a. *Distributed Energy Resource Scope of Services*: Voltus will manage Customer's participation in the Program(s) listed on Exhibit 1, in accordance with rules set forth by the grid operator and/or utility ("Operator"). Voltus will (i) work with Customer to develop an appropriate curtailment plan; (ii) manage all aspects of Customer's participation in the Program(s) and (iii) process all Program payments in accordance with the rules set forth by the Operator.
   b. *Peak Saver Scope of Services*: Voltus will provide services to help Customer reduce and/or eliminate Customer's demand charges at the sites listed on Exhibit 1. Voltus will (i) analyze site-specific information (e.g., energy interval data, utility bills), (ii) present to customer savings available for each site based on specific energy reduction strategies, (iii) finalize with site personnel the demand reduction plan and dispatch protocol, (iv) notify and dispatch sites in connection with potential peak demand hours, and (v) provide post-season analysis and reporting on savings delivered.
   c. *Voltlet and Voltapp:* Upon Customer's authorization, Voltus will equip Customer with a system that collects energy data ("Voltlet") and provides visibility of this data through the Voltus cloud ("Voltapp"). At the Customer's request, such system may enable remote distributed generation control and direct load management. Voltus will install the system at each Customer facility as identified on Exhibit 1, which may be amended with the Customer's consent to reflect additional locations.

3. **Customer Requirements**
   a. *Utility Data:* Customer hereby authorizes utility data access for Voltus for facilities listed on Exhibit 1.
   b. *Voltus System Installation:* In the event a Voltlet needs to be installed, Customer will provide Voltus personnel, or their designee, with access to meters and/or equipment at facilities listed on Exhibit 1.
   c. *Acceptance Testing:* If the program requires acceptance testing, Customer will work with Voltus to prove Customer capability at each facility in a timely manner prior to Voltus registration of each facility in the Program(s).
   d. *Distributed Energy Resource Performance:* Customer will reduce electrical demand when notified by Voltus in accordance with Program rules. The Parties understand that the capacity listed on Exhibit 1 represents the best estimate of performance and that performance may vary.

4. **Payments**
   a. *Distributed Energy Resource Payment Sharing:* Voltus will pay Customer _____% of all payments obtained by Voltus owing to Customer's performance in the Program(s), up to the total enrolled amount, less $150 per Voltlet per month.
   b. *Peak Saver Shared Savings*: Customer will pay Voltus ___% of electricity demand charge savings owing to Customer's performance in accordance with this Agreement. Such payments are due to Voltus within forty-five (45) days of each calendar month in which the savings accrue to Customer. The calculation of savings for each site is defined on Exhibit 2. Notwithstanding the foregoing, any such payments owed to Voltus shall be subtracted from payments owed to Customer per paragraph 4a.
   c. *Underperformance:* In no event shall Customer be penalized for underperformance.
   d. *Payment Timing:* Voltus will issue customer payment within 45 days of Voltus's receipt of payment from the Operator for each program season.

5. **General Terms**
   a. *Limitation on Liability:* Voltus is not liable for Customer participation in Program(s). All remedies or damages are expressly waived, including any indirect, punitive, special, consequential, or incidental damages, lost profit, or other business interruption damages.
   b. *Choice of Law:* This Agreement shall be governed by, construed, and enforced in accordance with the laws of the State of _____ without giving effect to choice of law rules.

Page - 1

Voltlet

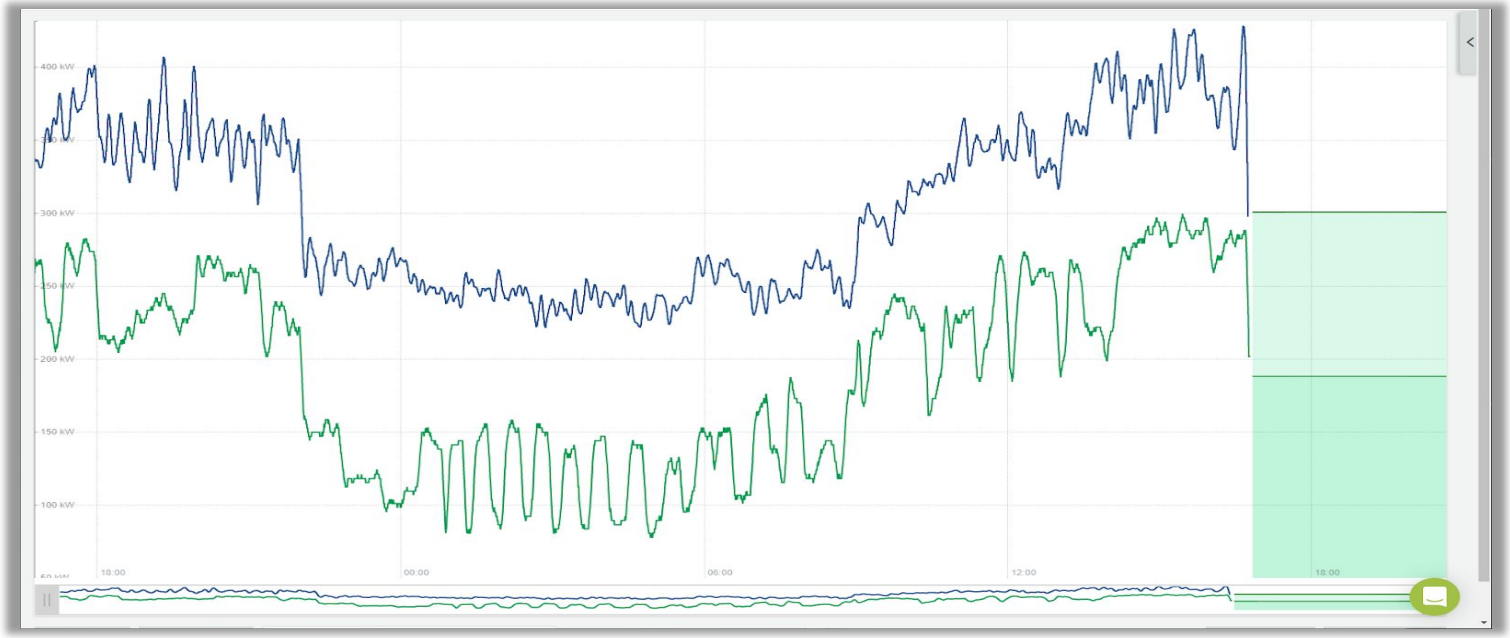
Data recorder reads utility meter’s KYZ pulse

Demand Response Simplified

Customers **earn cash** to reduce electricity consumption in response to a market signal

Operating Reserves Example

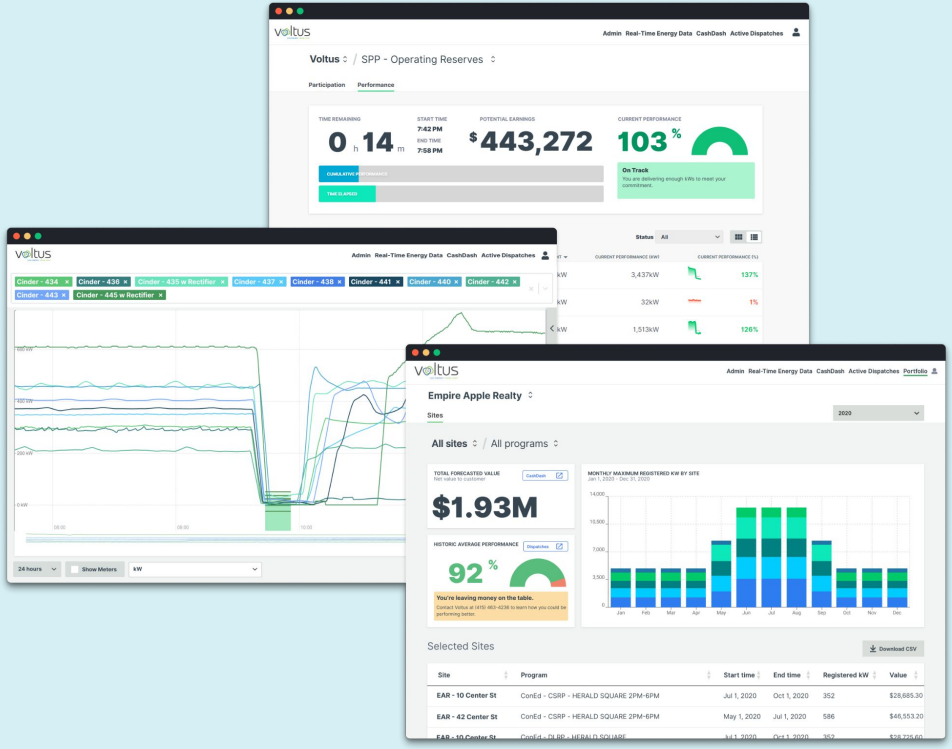
SPP Retails stores with OpenADR Integration



Technology to Make Life Easier

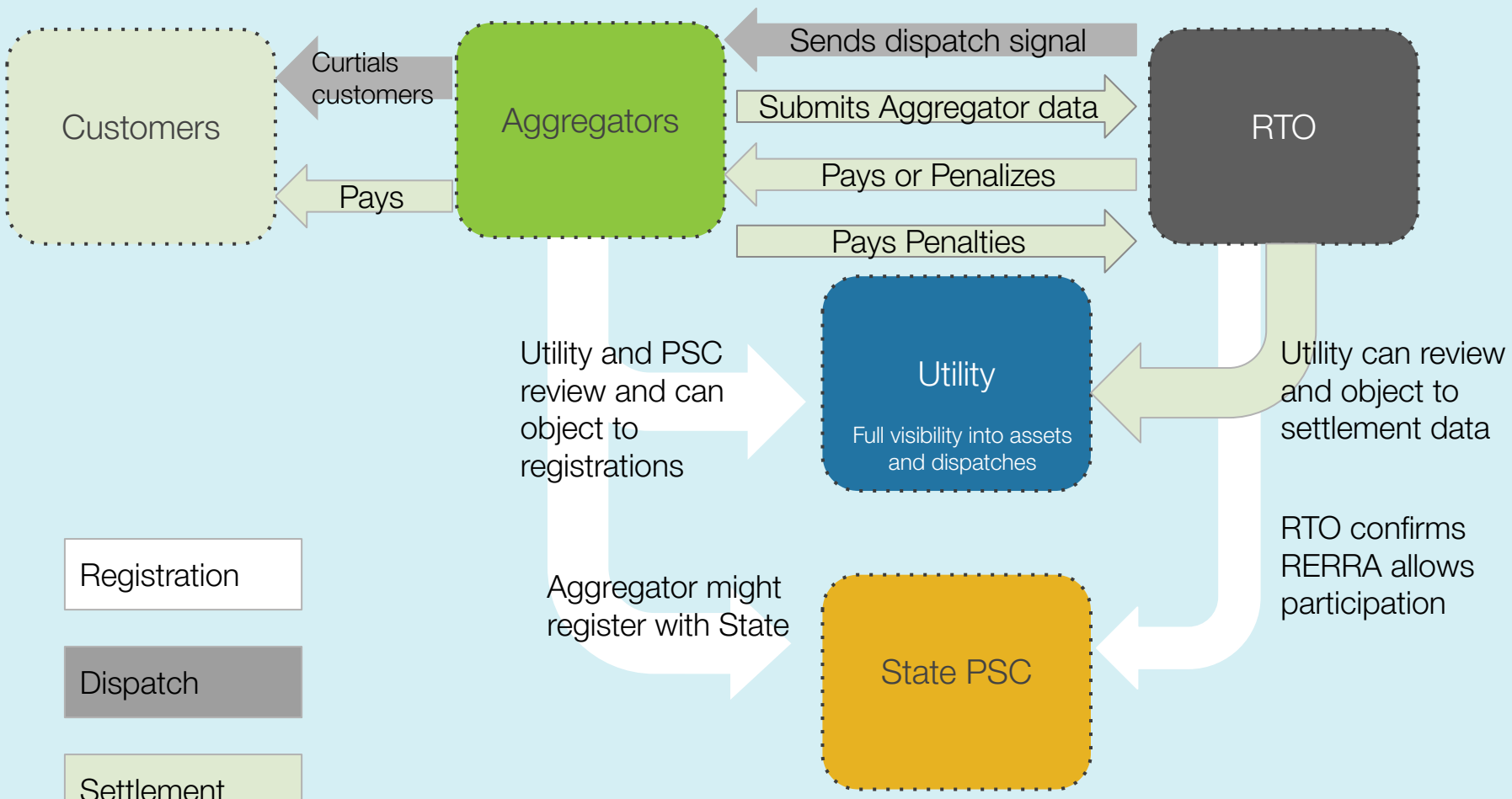
VoltApp speaks the language of cash and simplifies the complexities of market participation.

- **Real-time Energy Data**
- **PortfolioDash**
- **CashDash**



Wholesale Market Programs

	MISO	SPP
Energy	**Real-Time**	Real-Time
	Day Ahead	Day Ahead
Ancillary Services	**Spinning Reserve**	**Spinning Reserve**
	Supplemental	Supplemental
	Regulation	Regulation
Capacity	**Load Modifying Resources**	N/A


Customers
Curtials customers
Pays
Aggregators
Sends dispatch signal
Submits Aggregator data
Pays or Penalizes
Pays Penalties
RTO
Utility and PSC review and can object to registrations
Utility
Full visibility into assets and dispatches
Utility can review and object to settlement data
Aggregator might register with State
State PSC
RTO confirms RERRA allows participation
Registration
Dispatch
Settlement

Competitive DR in Vertically Integrated States

Thirteen states have opted out, many have not

West Virginia is vertically integrated, and never opted out

- Aggregators work with retail customers to participate in PJM's programs
- Utilities have DR programs
- Utilities plan for load the same whether it is Utility or Third-Party DR

Voltus provides operating reserves in Oklahoma and Kansas

Session 5

Aggregation and Perspective on Demand Response

David Bloom, Manager, Energy Acquisition, BGE

Missouri PSC FERC Order 2222 Informational Workshop: Aggregation and Perspective on Demand Response

June 29, 2021

David Bloom, Manager, BGE Energy Acquisition

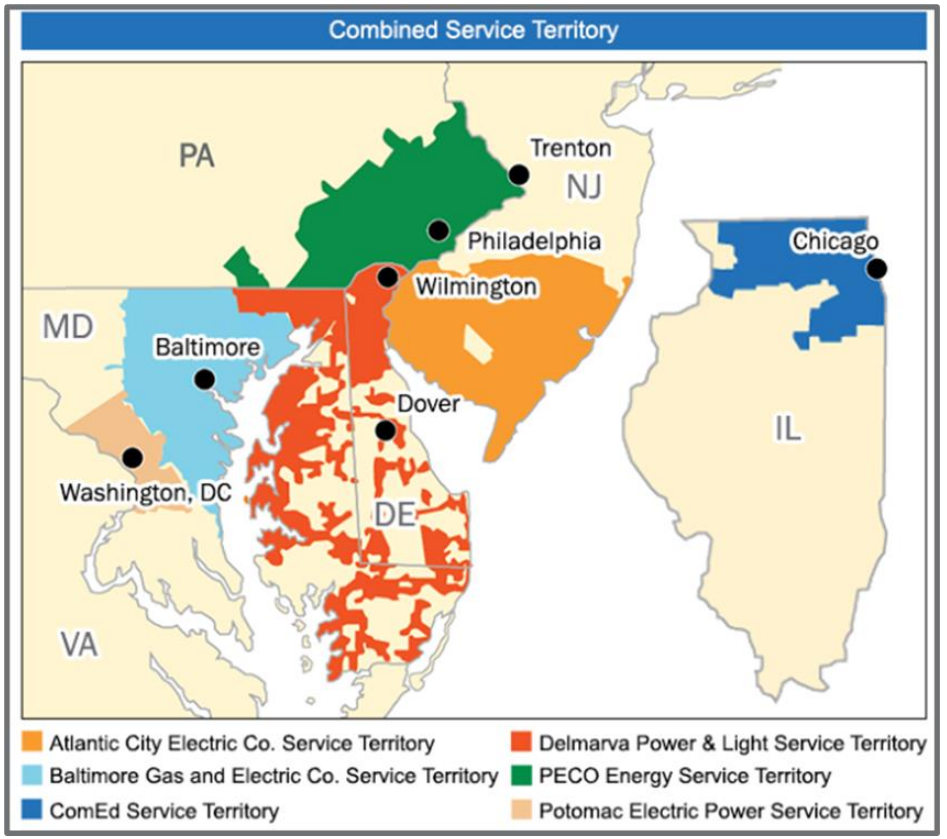
BGE
An Exelon Company

THAT'S SMART ENERGY℠

BGE: At-a-Glance

- The Leading Gas and Electric Provider in Maryland

  - **Founded:** 1816 — nation's first gas utility and one of the first electric utilities
  - **CEO:** Carim Khouzami
  - **Employees:** 3,200
  - **Customers Served:** 1.28 million+ electric and 670,000+ gas customers
  - **Region:** State of Maryland
    - Electric service ~2,300 square miles
    - Gas service ~800 square miles



BGE Residential Demand Response Programs

- **PeakRewards**
  - 2008
    - One-way AC Switches and Thermostats
    - ~310,000 Customers enrolled (~345,000 devices)
    - Customers sign up for 50%/75%/100% cycling
    - 2017: began using upgraded thermostats

- **Smart Energy Rewards**
  - 2013 – 2016: deployment of AMI
    - Enabled **Energy Savings Days** for all customers with AMI to earn **Peak Time Rebate**
    - High participation rates: ~75% of customers earn a **Peak Time Rebate**
    - ~1M customers

BGE Residential Demand Response Programs

- **Connected Rewards**
  - 2020
    - Bring Your Own Device (BYOD)
    - Customers sign up for a temperature offset program (e.g. 4 degrees)
    - Earn an annual $50 eGift card
    - Over 22K devices currently enrolled after the first year

PJM Market Participation

- BGE is the Curtailment Service Provider (CSP)
- Aggregate the capability from ~310,000 PeakRewards customers and ~700K behavior-only customers (i.e. no device)
- BGE offers in PJM capacity auction and settles in energy market (since beginning of Reliability Pricing Model or RPM)
- First to provide Price Responsive Demand (PRD) load management resource in PJM (capacity)
  - 240 MW in 2021/2022 Delivery Year
  - PRD requires AMI, supervisory control and dynamic retail rate (Peak Time Rebate

Contact Info

David Bloom

Manager, BGE Energy Acquisition

david.bloom@bge.com

Session 6

Lessons Learned Transitioning from DR Aggregation to DER Aggregation

Peter Millburg, Senior Manager, Regulatory Compliance, Ameren Illinois

Implementing FERC Order 2222

Applicable Experience from a Utility in a Restructured MISO State

June 29, 2021

Table of Contents

Ameren Illinois - Background

- Combination utility
  - 1.2 million electric customers, 800,000 natural gas customers
- Gas choice implemented in 1980's; electric choice in the 1990's
  - Currently 57% of electric customers and 77% of electric load served by 3rd parties
- All utility-supplied electric power and energy sourced through the MISO market
  - No utility-owned generation
- Standard generator interconnection rules and net metering implemented in 2008
  - 5,500+ generator interconnections, most of which occurred starting in 2015
- Residential demand response opt-in aggregation program implemented in 2015
  - 135,000± customers currently enrolled, 16MW of peak curtailable load

Applicable Experience

- Use of Portals to Efficiently and Securely Support Enrollment, and Effect Customer Decisions
  - EDI for electric and gas choice enrollments by suppliers
    - 40+ electric and gas suppliers
  - Government Portal to enable aggregation of residential and small non-residential customers for electric choice
    - 391 communities enacted aggregation programs
  - Renewables Portal to enable applications for rebates for use of smart inverters in generator interconnections
    - 5,000 applications and $32 million in rebates paid since February 2019

Use of Portals Key to Supporting and Managing Aggregation Program Enrollments

- Users must first be authorized by the LDC to access portal/make data entries and view their reports

- Programming logic prevents duplicative enrollments
  - Supported by tariff language

- Check-boxes require users to affirmatively confirm their compliance with MISO/state tariff requirements before enrolling customers
  - For example, if written customer authorization is required for enrollment, aggregator has to affirm that written approval has been secured
  - Responsibility for compliance lies with the aggregator

- Selection of the type of aggregation program triggers the type of customer data and reports available to aggregator
  - Also triggers the timeframes in which the data is made available (e.g. frequency regulation might be required in near real-time.)

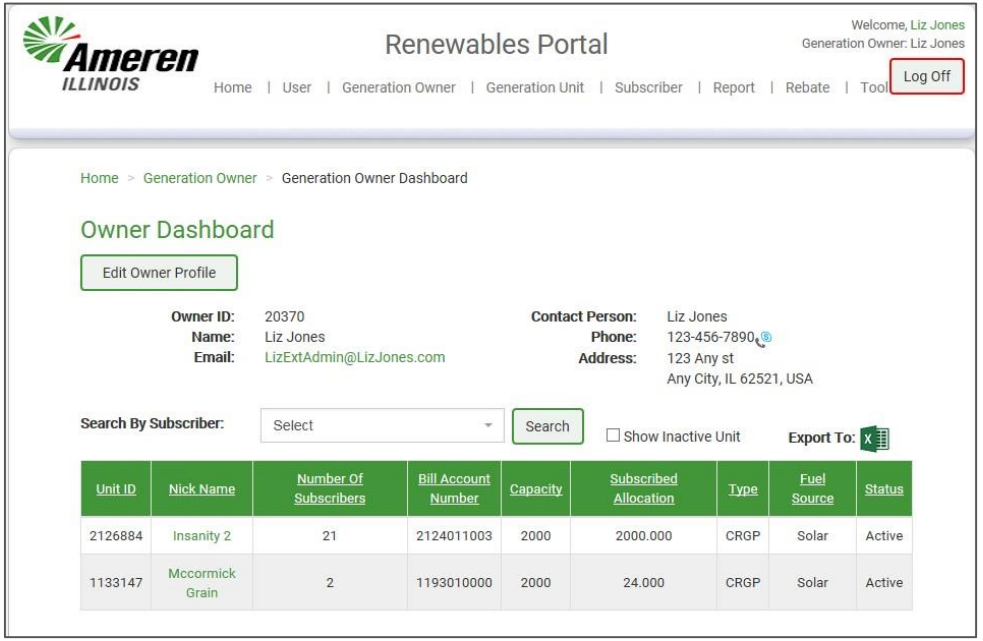
Renewables Portal
Community Solar Example

Generation Owner

(external admin view)

Navigation Box which will appear on top of every page in the portal.

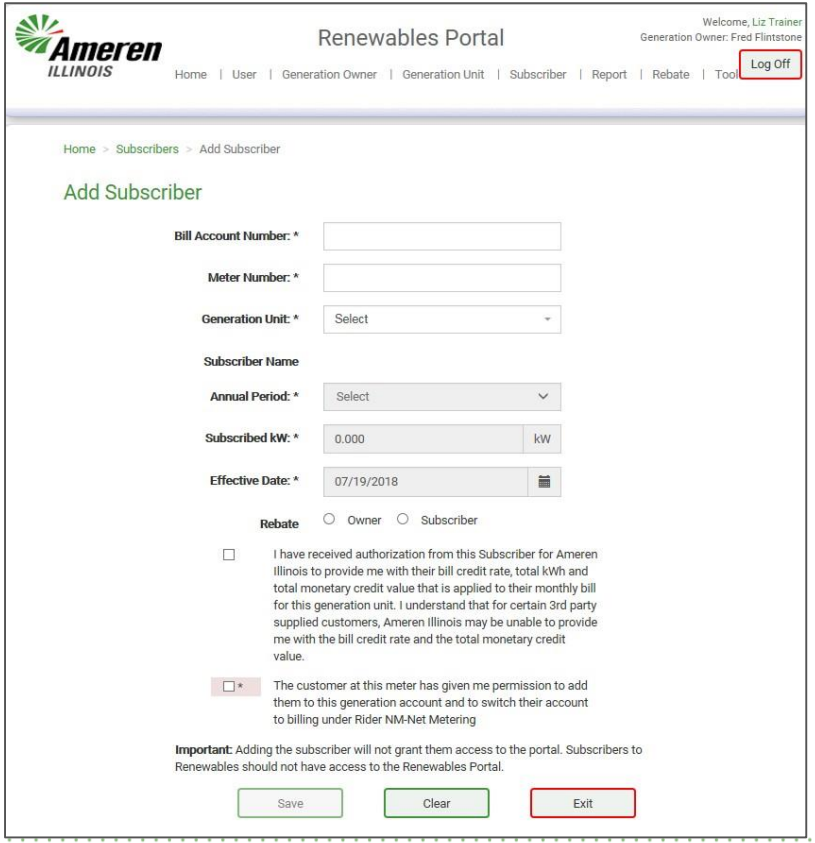
- Edit User Profile by clicking on name
- Home page is the Owner Dashboard
- User will show you a list of your portal users
- Generation Owner is Home Page
- Generation Units will show a list of your units
- Subscribers will show a list of your Subscribers
- Reports will show you available reports
- Tools are not available to Generation Owners



- Edit your Owner Profile
- Click on Email address to open an email
- Search By a Subscriber
- Checkbox to display Inactive Units
- Export Unit Table to Excel
- Generation Unit Table provides Unit Details
- Click on Unit Nick Name takes you to the Generation Unit Subscription Detail Page

Registering Subscribers

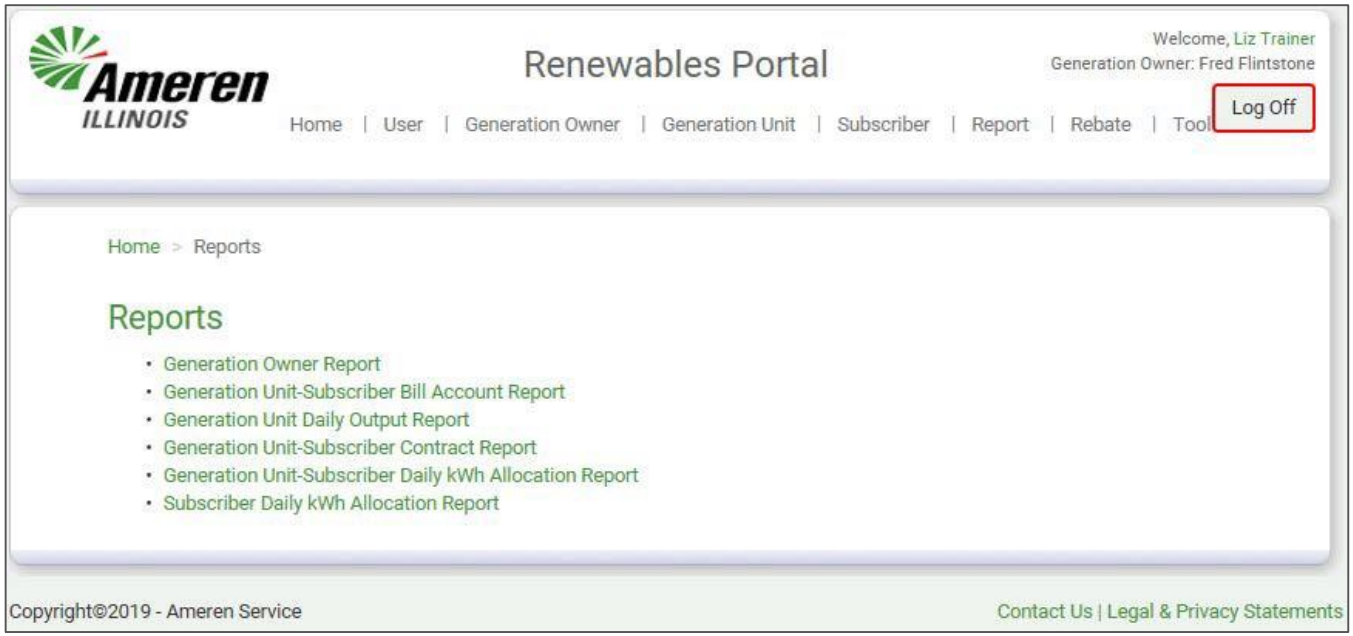
Add Subscriber



- Enter Subscriber's Ameren bill account number
- Enter Subscriber's electric meter number
- Select a Generation Unit
- Subscriber's name will auto populate by Ameren
- On a DS-1 and DS-2 you will need to select the annual period of April or October, this field will populate if the subscriber is already on net metering
- Enter Subscribers allocated kW
- Enter the Effective date Ameren should start allocation
- Check the boxes confirm the customer has given you permission to enroll them in Aggregated Net Metering and provided authorization to receive customer specific data
- Save
- Clear will clear form to allow entry of another subscriber
- Exit

Reports

Reports


Ameren ILLINOIS
Renewables Portal
Welcome, Liz Trainer
Generation Owner: Fred Flintstone
Log Off
Home | User | Generation Owner | Generation Unit | Subscriber | Report | Rebate | Tool
Home > Reports
Reports
Generation Owner Report
Generation Unit-Subscriber Bill Account Report
Generation Unit Daily Output Report
Generation Unit-Subscriber Contract Report
Generation Unit-Subscriber Daily kWh Allocation Report
Subscriber Daily kWh Allocation Report
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2222 Implementation Assumptions/Questions/Concerns

- Allowing sufficient time for implementation, and recognizing differences between states are critical to successfully implementing 2222
  - More details on following pages, but generally speaking:
    - Regardless of vertically integrated/restructured status, MISO's issuance of final tariffs/business processes are critical to enable states/utilities to begin their implementation of 2222
    - Utilities in a restructured states are better positioned to implement 2222 with regard to existing digital systems, organizational structure, tariffs and experience interacting with 3rd parties acting on behalf of customers
      - Important to support the needs of both participating and non-participating customers
    - Smart meter deployment/implementation status significantly impact utilities' ability to support 2222

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- Supporting/enabling 2222 is doable, but much is still undefined
  - Believe that there will be no new products or services expected initially
    - Aggregators will sell ancillary services and energy
  - Respective roles between RTO's (in Ameren's case – MISO) and local distribution companies (LDC) still being defined (MISO has issued Iteration 1 of its 2222 filing)
    - Believe that LDC will primarily be source and conduit of meter data needed for aggregators and MISO to confirm delivery of service
      - Some scenarios envision LDCs collecting and conveying data from non-LDC devices such as inverters
    - MISO will have sole responsibility for administering and auditing transactions with aggregators
  - In addition to registering as a Market Participant at MISO, will aggregators be required to register/be certified at the state level?
    - Certification/official identification of aggregators at either level will enable Ameren to know who should have access to the customer information through portals

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- Cost recovery expectations must be clearly addressed
  - For any customer locations where enhanced data streams (speed, sourced from customer equipment, etc.) are required to enable customer to participate in MISO markets
  - Cost of building and operating portals to support enrollment
  - Affordability of energy service by non-participating customers
    - Substantial subsidies already provided for generator development through REC programs
  - Enhanced DERMS capability will likely need to be built to both digitally communicate with MISO and ensure distribution system reliability, and will need to support both monitoring and control purposes (DERMS+optimization)
  - Will likely require incremental staffing resources, and new skill-sets

- MISO's aggregation implementation rules need to recognize differing LDC operations/structure/experience in vertically-integrated and restructured states
  - Varying levels of smart meter deployments; existing tariff structures/systems/staffing to support retail DER compensation programs and 3rd party activity, etc.

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- Especially in vertically-integrated states, existing consumer fraud statutes and Commission rules should be reviewed to ensure that sufficient consumer protections are in place
  - The preferred model is for LDCs to not assume an enforcement role beyond requiring aggregators to affirm whatever is required before providing customer/meter data
  - Commissions and LDCs shouldn't assume that they know best for the customer, and limit their choices in the desire to "protect" customers
    - Numerous examples of customers making choices that don't appear to be in their best economic interests – their right to make decisions, good or bad

- Billing and enrollment errors can always be fixed

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- Retail tariffs will have to be modified/created to support aggregation, and ensure consistency between retail and FERC programs
  - e.g. a customer enrolled in QF can't also sell the output of their generation directly into the wholesale market
    - Electric choice experience - first enrollment within the enrollment window controls, and any subsequent enrollment attempts within window are rejected If errant, customers need to address it with the suppliers involved.
    - Demand response enrollment uses similar logic - customer can't sell same capacity into same market through two different aggregators
      - Registration logic un-enrolls customer from Ameren Illinois' residential aggregation program if they enroll their capacity with an aggregator
        - » Supported by tariff language

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- It appears that the existing generator interconnection process will support known aggregation needs
  - Don't conflate physical and operational requirements associated with connecting a parallel energy source with processes associated with individual compensation programs
    - REC award experience in IL with signed IA required prior to award lottery
  - If MISO products just need data on energy/capacity supplied to grid at the point of interconnection, basic interconnection process will suffice
    - Enhanced needs, such as utility meters on generators, or enhanced data transmission speed to aggregator/MISO, can also be addressed using standard attachments to standard interconnection agreements
      - e.g. data from facilities providing frequency regulation will need to be provided in real-time/near real-time to MISO
  - Standard and application-specific interconnection costs responsibility of interconnection applicant
    - Includes any post-permission to operate modifications needed to support customer's participation in aggregation programs

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- Will MISO economic dispatch of assets conflict with LDC operational/reliability needs?
  - To what extent will MISO expect LDC to coordinate operation/maintenance/circuit outage activities
  - Prefer that LDC continue to operate its system with the primary focus of reliability and safety for load customers, and require aggregators to address any deliverability issues with MISO

- Liability/cyber concerns if required to collect and transmit data from customer devices, especially mobile devices
  - In addition to inverters, some discussion about compensating EV owners for battery discharge regardless of location where discharge occurs
    - LDC systems tie meters to customers for billing and crediting purposes
    - Complications associated with service territory rights and varying metering capabilities between LDCs
  - LDC has no authority/responsibility for ensuring accuracy of metering data from customer-owned devices such as inverters


Ameren
ILLINOIS

Session 6

Lessons Learned Transitioning from DR Aggregation to DER Aggregation

Suzanna Mora-Schrader, Director,

Utility Initiatives, Exelon Utilities

Session 6

Lessons Learned Transitioning from DR Aggregation to DER Aggregation

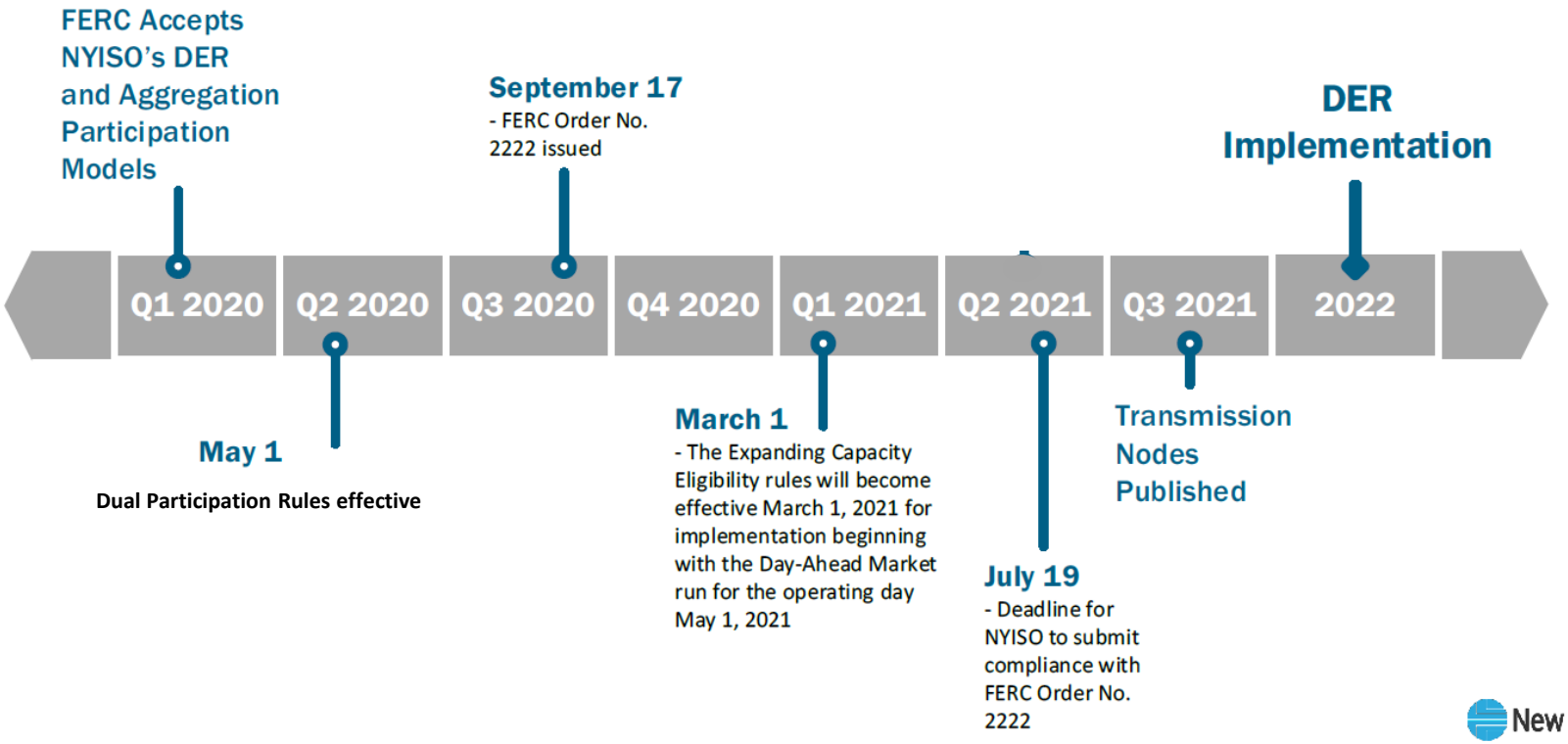
Bahaa Seireg, Project Manager, Con Edison,
and *John Ramano, Section Manager,*
Utility of Future Team, Con Edison

FERC Order No. 2222 in the New York

John Romano, Section Manager, Utility of the Future
Bahaa Seireg, Project Manager, Energy Policy & Regulatory Affairs

June 29, 2021

NYISO Aggregation & Participation Model Timeline



NYISO DER Aggregation & Participation Model

- On January 23, 2020, FERC accepted the NYISO's proposal regarding the aggregation of DERs
  - The proposal has many of the elements found in Order 2222.
  - NYISO's compliance filing does not require as much work as compared to other RTOs.
- NYISO plans on initiating Order 2222 stakeholder process to discuss compliance filing in Q2 2021.
  - Compliance filing due in July 2021.

NYISO Aggregation & Participation Model

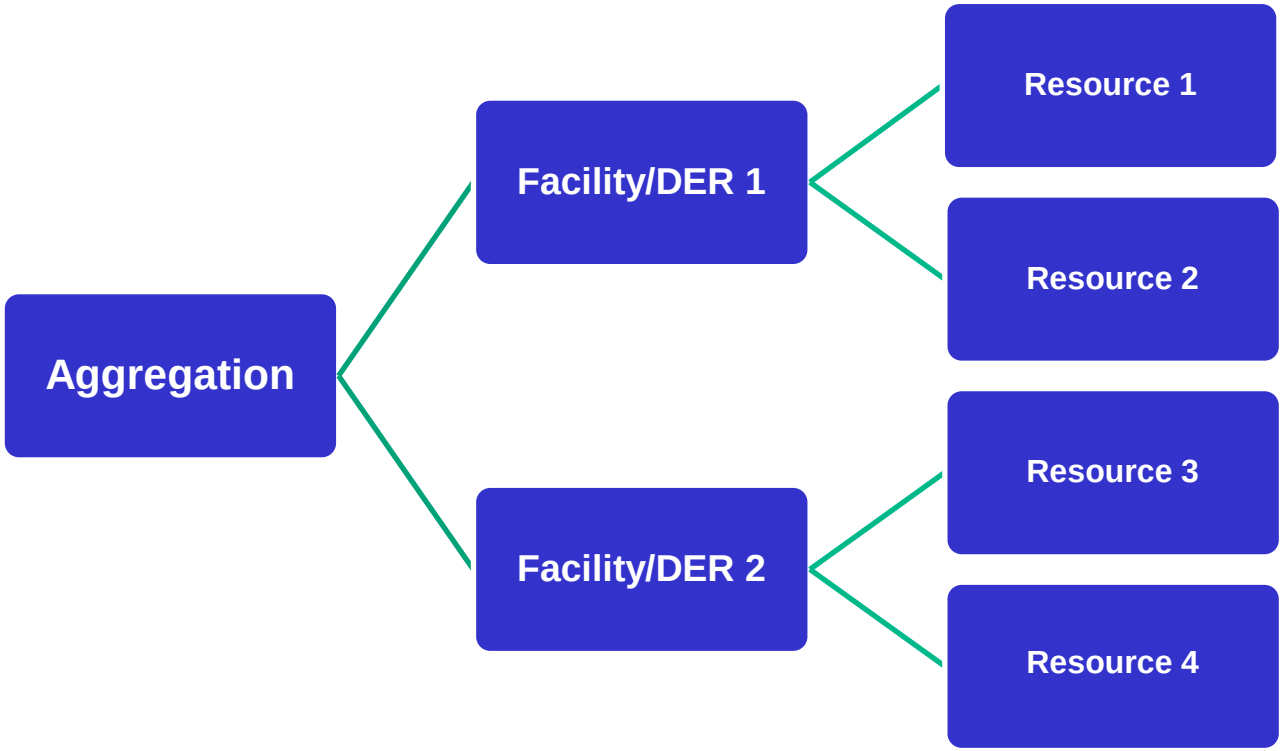
Basic Aggregation Model*

Metering:
Aggregate Metering Data sent to NYISO

Bidding: Done at the Aggregation Level

Interconnection Studies:
Performed at Facility/DER Level

Telemetry Requirements:
Each Facility/DER must have 6-Second Telemetry



- "Resources" such as generators smaller than 20 MW that can inject energy directly onto the grid such as ,wind, solar, cogeneration, and energy storage resources, can be defined as a "DER".

Aggregation Size

- FERC Order No. 2222
  - FERC Order No. 2222 permits a single qualifying DER (i.e., one that can, by itself, meet all applicable requirements for an aggregation) to be an “aggregation”.
- NYISO DER Aggregation & Participation Model
  - NYISO DER Aggregation & Participation Model defines an Aggregation as two or more individual DERs (unless the DER is a Demand Side Resource).
  - Like Order No.2222, minimum offer requirements for all Aggregations will be 100 kW.
  - Like Order No.2222, no threshold for maximum size of an aggregation.

Interconnection Requests

- FERC Order No. 2222
  - Resources located on the distribution system, any subsystem thereof or behind a customer meter must go through an interconnection study.
- NYISO DER Aggregation & Participation Model
  - Interconnection requirements focus on the Facility/DER level, rather than either the more granular Resource level or the broader Aggregation level.
  - This is the case even if the Resources behind the same Facility/DER meter are different technologies (e.g., energy storage and solar).

Dual Participation

- FERC Order No. 2222
  - Must be able to participate in wholesale Energy, Ancillary Services, & Capacity Markets.
  - A DER can participate in both retail and wholesale programs and be compensated in each for providing distinctly different services.
- NYISO DER Aggregation & Participation Model
  - New participation model for aggregations of resources allows such aggregations to participate in the NYISO-administered energy and ancillary services markets and NYISO's installed capacity market (ICAP Market)
  - The NYISO's tariffs do not restrict wholesale market compensation for services provided at the distribution utility's direction.
  - It is the aggregator's responsibility to optimize dispatch of their aggregation and to ensure they are fulfilling the obligations of the services they are choosing to provide.

Location

- FERC Order No. 2222
  - Commission proposed to require each RTO/ISO to revise its tariff to establish locational requirements for distributed energy resources to participate in an aggregation that are as geographically broad as “technically feasible”.
- NYISO DER Aggregation & Participation Model
  - Requires that each individual Facility/DER within an Aggregation be electrically located in the New York Control Area and electrically connected to the same NYISO-identified transmission node.
  - The NYISO intends to publish the new transmission nodes publicly one year in advance of the go-live date.

Distribution Utility Coordination

- FERC Order No. 2222
  - Requires each RTO/ISO to revise its tariff to allow distribution utilities to override RTO/ISO dispatch, when necessary, to maintain the reliable and safe operation of the distribution system.
- NYISO DER Aggregation & Participation Model
  - The NYISO intended to locate much of the coordination protocols between the NYISO, utilities, and aggregators in manuals and procedures. Order No. 2222 requires RTOs and ISOs to include some of that coordination in the tariffs.
  - Dispatch override can happen at any time.

Cost Recovery

- FERC Order No. 2222
  - The reforms adopted in this final rule do not preclude or limit state or local regulation of retail rates.
  - Appropriate, on a case-by-case basis, for distribution utilities to assess a wholesale distribution charge on distributed energy resource aggregators participating in RTO/ISO markets.
- NYISO DER Aggregation & Participation Model
  - Interconnection costs as well as metering and telemetry are allocated to the developer.
  - The systems that allow the utility to monitor the output of the DER and allow the utility to communicate with the NYISO are allocated to ratepayers.
  - At this point, utility rate recovery through NYPSC is what has been proposed.

Implementation

- Registration/Interconnection
  - What information will the utilities request during the enrollment process? Does required information vary depending on DER type, size, etc.?
  - To the extent these data requirements overlap with what NYISO will require, is there an opportunity for utility-NYISO coordination to avoid duplicative requests of the Aggregator?
  - What type of interconnection study will the utility perform?
    - Dispatching resources individually has a different impact from dispatching all the resources in the aggregation.
    - How do utilities model and study aggregated DER acting in coordination across circuits?

- Operations/Markets
  - Utilities must develop an operational systems impact tool that can be used to validate wholesale market schedules against current distribution system conditions.
  - Utilities are working with the NYSIO to finalize Transmission Nodes for the aggregation of local, distribution connected DERs.
  - Update, refine duplicative compensation mapping matrix to track which resources are participating in retail programs and their eligibility to receive payments from the wholesale market.

Implementation

- **Metering/Settlement**
  - Reconstituted load reporting processes.
  - New billing functionality required to accommodate sub-metering configurations.
  - 3rd Party owned metering .

- **Telemetry**
  - New low-cost forms of telemetry needed to reduce barriers to market entry.
  - IT Architecture and Cyber Security solutions may be new for utilities.
    - What level of effort is required on the Aggregator's part to provide the utility with its market schedules? What format and medium will these be communicated with?

- Operations
  - Significantly increased volume of communications required.
  - Conflicting Transmission and Distribution priorities.

Session 7

Missouri Jurisdictional Update

John Borgmeyer, Litigation Counsel,
Missouri Public Service Commission

DISTRIBUTED ENERGY RESOURCES, AGGREGATORS, AND COMMISSION JURISDICTION

John D. Borgmeyer, Attorney, Office of the General Counsel

Missouri Public Service Commission

DISCLAIMER

This information reflects my views alone, and does not represent the views or opinions of the Missouri Public Service Commission, Commissioners, Staff or any other person.

FERC FEDERAL POWER ACT (FPA) JURISDICTION

- Transmission of electric energy in interstate commerce;
- Sale of electric energy at wholesale in interstate commerce;
- All facilities for such transmission or sale of electric energy;

FERC JURISDICTION

- FERC definition of “public utility” = any person who owns or operates facilities subject to the jurisdiction of the Commission.
- **All rates and charges made, demanded, or received** by any federal public utility for or in connection with the transmission or sale of electric energy subject to the Commission's jurisdiction.
- **All rules, regulations, practices, or contracts affecting** jurisdictional rates, charges, or classifications are subject to FERC jurisdiction.

STATE JURISDICTION
AREAS NOT OCCUPIED BY FERC

- Retail sales and services;
- Generation facilities;
- Local distribution facilities;
- Facilities only for the transmission of electric energy in intrastate commerce;
- Facilities for the transmission of electric energy consumed wholly by the transmitter;
- Except as specifically provided in the FPA.

FEDERAL SUPREMACY

- The Supremacy Clause of the U.S Constitution renders federal law the "supreme Law of the Land."

- Congress may "pre-empt, *i*.e., invalidate, a state law through federal legislation."

Nat'l Ass'n of Regul. Util. Commissioners v. Fed. Energy Regul. Comm'n, 964 F.3d 1177, 1187 (D.C. Cir. 2020).

THORNY ISSUES

New technologies and business models such as distributed energy resources and aggregations present a series of legal questions that “lie at the confluence of State and Federal jurisdiction.” (FERC Order 745)

FERC JURISDICTION
DER AGGREGATIONS

- DER Aggregation's injections to RTO/ISO = **wholesale sales** subject to the FERC's jurisdiction. (Order 2222 P. 40).

- DER Aggregator making sales of energy considered a FERC public utility. (Order 2222 P. 42).

FERC JURISDICTION OVER DISTRIBUTED ENERGY RESOURCE AGGREGATIONS

RTO/ISO market rules governing sales by demand resources (e.g. demand response and energy efficiency) = **practices affecting wholesale rates.** (Order 2222 P. 41).

DER Aggregator of only demand resources or net metering customers that are not net sellers not considered a FERC public utility. (Order 2222 P. 42).

INDIVIDUAL DER RESOURCES

- FERC only exercising jurisdiction in this final rule over the sales by distributed energy resource aggregators into the RTO/ISO markets.
- Individual DER included in an aggregation are not declared a FERC public utility. (Order 2222 P. 43).
- States “cannot broadly prohibit the participation in RTO/ISO markets of all distributed energy resources or of all distributed energy resource aggregators.” (Order 2222 P. 58).

STATE REGULATION OF DER AND AGGREGATORS

- "We reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements." (Order 2222 P. 44).

- Matters related to the distribution system:
  - design,
  - operations,
  - power quality,
  - reliability,
  - and system cost…

SECTION 386.250, RSMO
JURISDICTION OF THE PSC

The jurisdiction, supervision, powers and duties of the public service commission herein created and established shall extend under this chapter:

(1) To the **manufacture, sale or distribution** of … **electricity for light, heat and power, within the state**, and to persons or corporations owning, leasing, operating or controlling the same; and to… **electric plants**, and to persons or corporations owning, leasing, operating or controlling the same;

SECTION 386.250
JURISDICTION OF THE PSC

(5) To all **public utility corporations** and persons whatsoever subject to the provisions of this chapter as herein defined…

(6) To the adoption of **rules as are supported by evidence as to reasonableness** and which **prescribe the conditions of rendering public utility service,** disconnecting or refusing to reconnect public utility service and billing for public utility service.

SECTION 386.020(43) PUBLIC UTILITY DEFINED

- "Public utility" includes every… **electrical corporation**… as these terms are defined in this section, and each thereof is hereby declared to be a public utility and to be subject to the jurisdiction, control and regulation of the commission and to the provisions of this chapter…

SECTION 386.020(15) ELECTRIC CORPORATION DEFINED

- **"Electrical corporation"** includes **every corporation, company, association, joint stock company or association, partnership and person, their lessees, trustees or receivers … owning, operating, controlling or managing any electric plant** …. The term "electrical corporation" shall not include:
- (a) Municipally owned electric utilities operating under chapter 91;
- (b) Rural electric cooperatives operating under chapter 394;
- (c) **Persons or corporations not otherwise engaged in the production or sale of electricity at wholesale or retail that sell, lease, own, control, operate, or manage one or more electric vehicle charging stations;**

- A public utility's electric vehicle charging stations constitute "electric plant."

- *Kansas City Power & Light Co.'s Request for Auth. to Implement a Gen. Rate Increase for Elec. Serv. v. Missouri Pub. Serv. Comm'n*, 557 S.W.3d 460 (Mo. Ct. App. W.D. 2018).

SECTION 386.020(14) ELECTRIC PLANT DEFINED

"Electric plant" includes all **real estate, fixtures and personal property operated, controlled, owned, used or to be used for or in connection with or to facilitate** the **generation, transmission, distribution, sale or furnishing of electricity for light, heat or power;** and any conduits, ducts or other devices, materials, apparatus or property for containing, holding or carrying conductors used or to be used for the transmission of electricity for light, heat or power;

SECTION 393.170, RSMO
CERTIFICATE OF CONVENIENCE AND NECESSITY (CCN)

- 1. No… electrical corporation… shall begin construction of a[n] electric plant… other than an energy generation unit that has a capacity of one megawatt or less, without first having obtained the permission and approval of the commission.

ELECTRIC PLANT?

- **"Electric plant"** includes all **real estate, fixtures and personal property operated, controlled, owned, used or to be used for or in connection with or to facilitate** the **generation, transmission, distribution, sale or furnishing of electricity for light, heat or power**; and any conduits, ducts or other devices, materials, apparatus or property for containing, holding or carrying conductors used or to be used for the transmission of electricity for light, heat or power;

- Applicability to DER aggregators?
- Applicability to DER?
- DER sales to aggregators?
- CCN?

SECTION 393.130
SAFE AND ADEQUATE SERVICE

- 1. **Every electrical corporation… shall furnish and provide such service instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable. All charges made or demanded by any… electrical corporation… shall be just and reasonable…**

- "We reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements." (Order 2222 P. 44).

SECTION 393.140
GENERAL POWERS OF THE PSC

- General supervision of all electric corporations, plants and system;
- Quality of service;
- Power to order such reasonable improvements as will best promote the public interest, preserve the public health, and protect customers and employees.

SECTION 386.310

- The commission shall have power… to require every person, corporation, municipal gas system and public utility to maintain and operate its line, plant, system, equipment, apparatus, and premises in such manner as to promote and safeguard the health and safety of its employees, customers, and the public…

PSC AUTHORITY OVER RETAIL RATES AND SERVICE

- Interconnection agreements and rules?
- Rules to ensure distribution system safety and reliability, data sharing, and/or metering and telemetry requirements?
- Overseeing distribution utility review of distributed energy resource participation in aggregations?
- Establishing rules for multi-use applications?
- Resolving disputes between distributed energy resource aggregators and distribution utilities over issues such as access to individual distributed energy resource data?
- Consumer protections?
- DER/Aggregator registration? Conditions?

Does Missouri law need to be amended or clarified with respect to DER and DER aggregators?

ARKANSAS CODE 23-18-1001 *ET SEQ.* REGULATION OF ELECTRIC DEMAND RESPONSE ACT

- Defines “aggregator of retail customers” and “demand response.”
- Provides that the “marketing, selling or marketing and selling” of demand response within the state by electric public utilities or aggregators of retail customers to retail customers or into wholesale electricity markets is subject to regulation by (1) The Arkansas Public Service Commission; or (2) The local governing authority in the case of a municipally owned electric utility or a consolidated municipal utility improvement district.

ARKANSAS CODE 23-18-1001 *ET SEQ.* REGULATION OF ELECTRIC DEMAND RESPONSE ACT

- Authorizes the Commission to establish the terms and conditions for the marketing and/or selling of demand response by electric public utilities or aggregators of retail customers to retail customers; or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets.
- Prohibits the Commission from regulating demand response investments or demand response actions of a retail customer on the customer's side of the electric meter.
- Prohibits the marketing and/or selling of demand response into wholesale electricity markets by aggregator or customer unless PSC or governing authority determines it is in the public interest.

QUESTIONS?

DISCUSSION?

THANK YOU!

Session 8

Lessons Learned from Other State Regulators

John Shenot, Senior Advisor,
Regulatory Assistance Project

29 June 2021

DER Aggregation: Lessons Learned from Other States

Missouri Public Service Commission

Informational Workshop for File No. EW-2021-0267

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1 Lessons Learned to Date: Market Participation and Impacts

Aggregation Comes in Different Forms

Examples

	Utility*	Third-Party
Utility adjusts load forecast	• Many utility DR/load control programs	• *Not applicable*
Aggregated DERs are bid into RTO/ISO markets as a resource	• Ameren Missouri's C&I DR program • BGE's Smart Energy Rewards • Green Mountain Power's Powerwall program	• Voltus DR contracts with customers in restructured states

*Or third-party under contract to utility – e.g., Ameren Missouri partners with Enel X

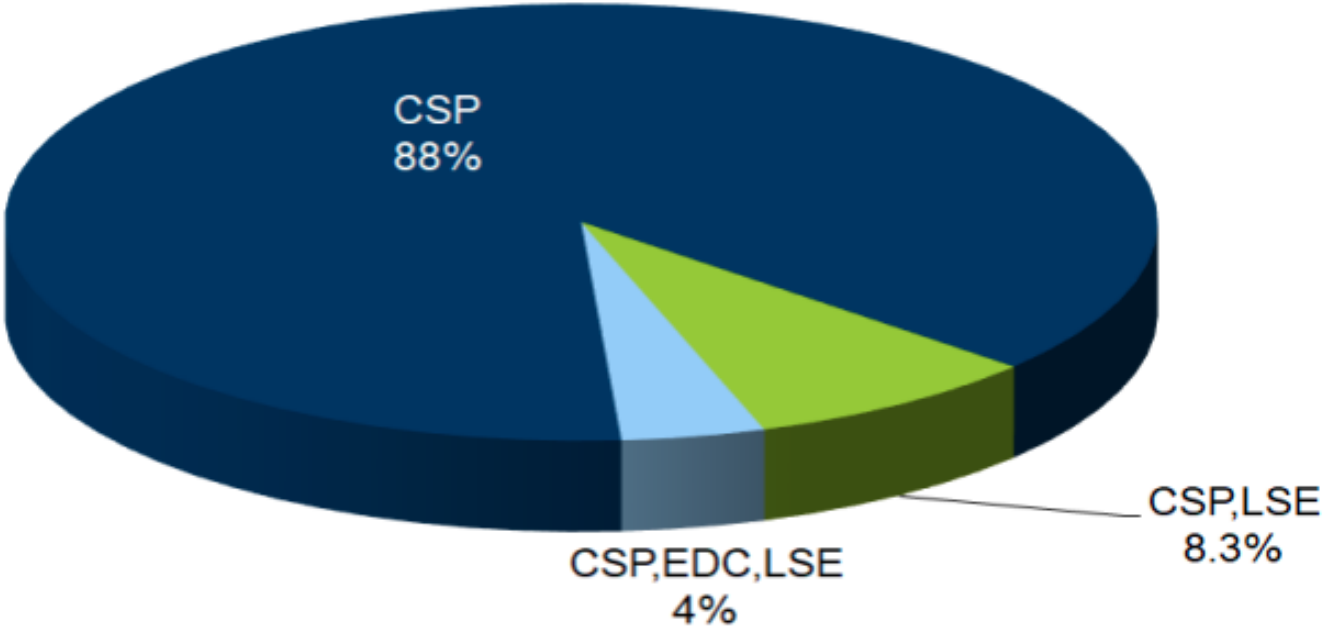
Utilities Do Participate as Aggregators: Maryland Example

Capacity Market Auction Year	MW Cleared in Capacity Auction			Capacity Market Revenues (Million $)
	DLC DR	EE	Dynamic Pricing	
2014/2015	772	179	267	54.4
2015/2016	625	175	426	69.5
2016/2017	554	226	461	53.6
2017/2018	536	243	387	51.3
2018/2019	522	172	378	31.6
2019/2020	230	184	225	10.6
2020/2021	265	199	425	28.1

Source: EmPOWER Maryland Energy Efficiency Act Report of 2021

But Third-Party Aggregators Have Dominated the Markets

Figure 4: DY 21/22 Confirmed Load Management DR Registrations Owner/Company Type



Source: PJM, *2021 Demand Response Operations Markets Activity Report*

Aggregation Lowers Wholesale Power Costs for All Customers!

Table 1 Summary of sensitivity results: 2017/2018 RPM Base Residual Auction

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Difference from Actual Results: RPM Revenue ($ per Delivery Year)	Difference from Actual Results: Percentage
0	Actual Results	$7,512,229,630	NA	NA
1	Annual Resources Only	$9,738,222,922	$2,225,993,292	29.6%
2	No Offers for DR or EE (Generation Resources Only)	$16,859,658,203	$9,347,428,573	124.4%
3	No Short-Term Resource Procurement Target Reduction	$9,947,329,539	$2,435,099,909	32.4%
4	No Short-Term Resource Procurement Target Reduction and Annual Resources Only	$10,932,522,889	$3,420,293,259	45.5%
5	No Short-Term Resource Procurement Target Reduction and No Offers for DR or EE (Generation Resources Only)	$23,870,404,571	$16,358,174,941	217.8%

Source: Independent Market Monitor for PJM, *The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses*

2 Lessons Learned to Date: State Regulation of Utilities and Aggregators

For Utility Aggregation, Most Regulatory Issues Were Familiar

- Would new utility DER programs be cost-effective?
- Would new programs serve the public interest?
- How could the Commission ensure fair competition between utilities (or their affiliates) and third-party aggregators?
- How would utility costs be allocated and recovered?
- Were utility expenditures prudent?

For Third-Party Aggregation, New Issues Had to Be Resolved

- Registration/licensing of aggregators
- Consumer protections & dispute resolution process
- Changes to utility programs or tariffs to avoid double compensation
- Cost allocation & cost recovery

Order 2222 May Generate Unique Issues for State Regulators

- Revise interconnection standards, rules and processes
- Revise data access and privacy policies
- Allow DR aggregation? (optional under Order 719)
- Allow DER aggregation for customers served by smaller utilities? (optional under Order 2222)
- Revise utility planning practices (e.g., IRP)?

Note that many regulatory issues around aggregation fall under FERC jurisdiction, not state PUC jurisdiction

About RAP

The Regulatory Assistance Project (RAP)® is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future.

Learn more about our work at raponline.org

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Extra Slides for Use if Relevant Questions Arise

FERC Order 2222 Definition of DER

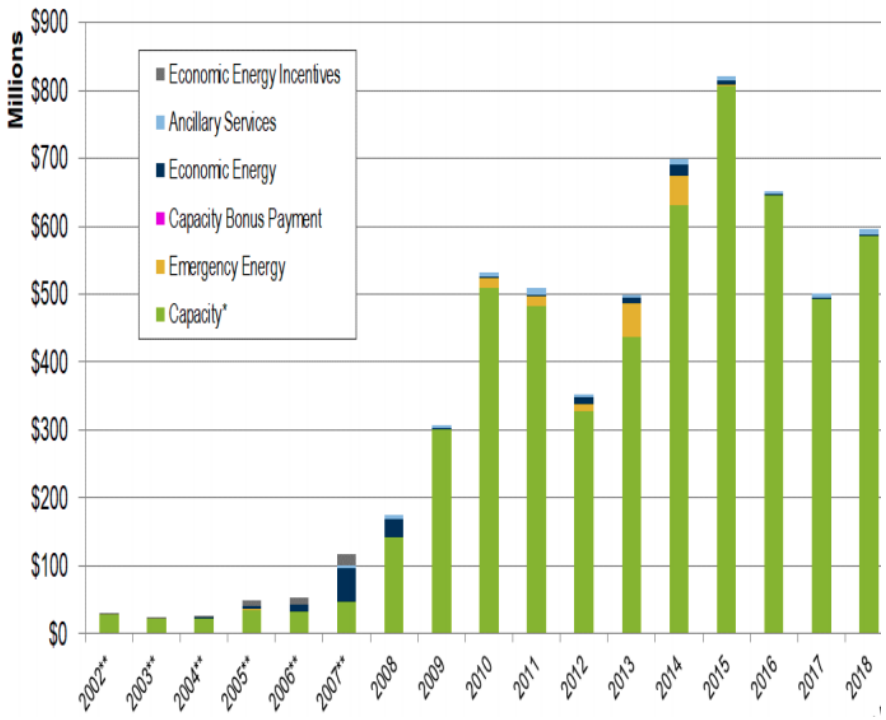
- DER includes ANY resource connected to the distribution system, in front of the retail meter or behind the meter, including:
  - Energy storage – electric and thermal
  - Distributed generation (DG)
  - Demand response (DR)
  - Energy efficiency (EE)
  - Electric vehicles and their supply equipment

DER Aggregations (other than EE and DR) to Date

- 7 DER aggregators registered in CAISO, including 1 IOU
- 1 Vermont utility (Green Mountain Power) bidding aggregated energy storage into ISO-NE ancillary services market
- 1 third-party aggregator of residential PV + storage (SunRun) has cleared ISO-NE capacity market
- Probably other examples, but not many

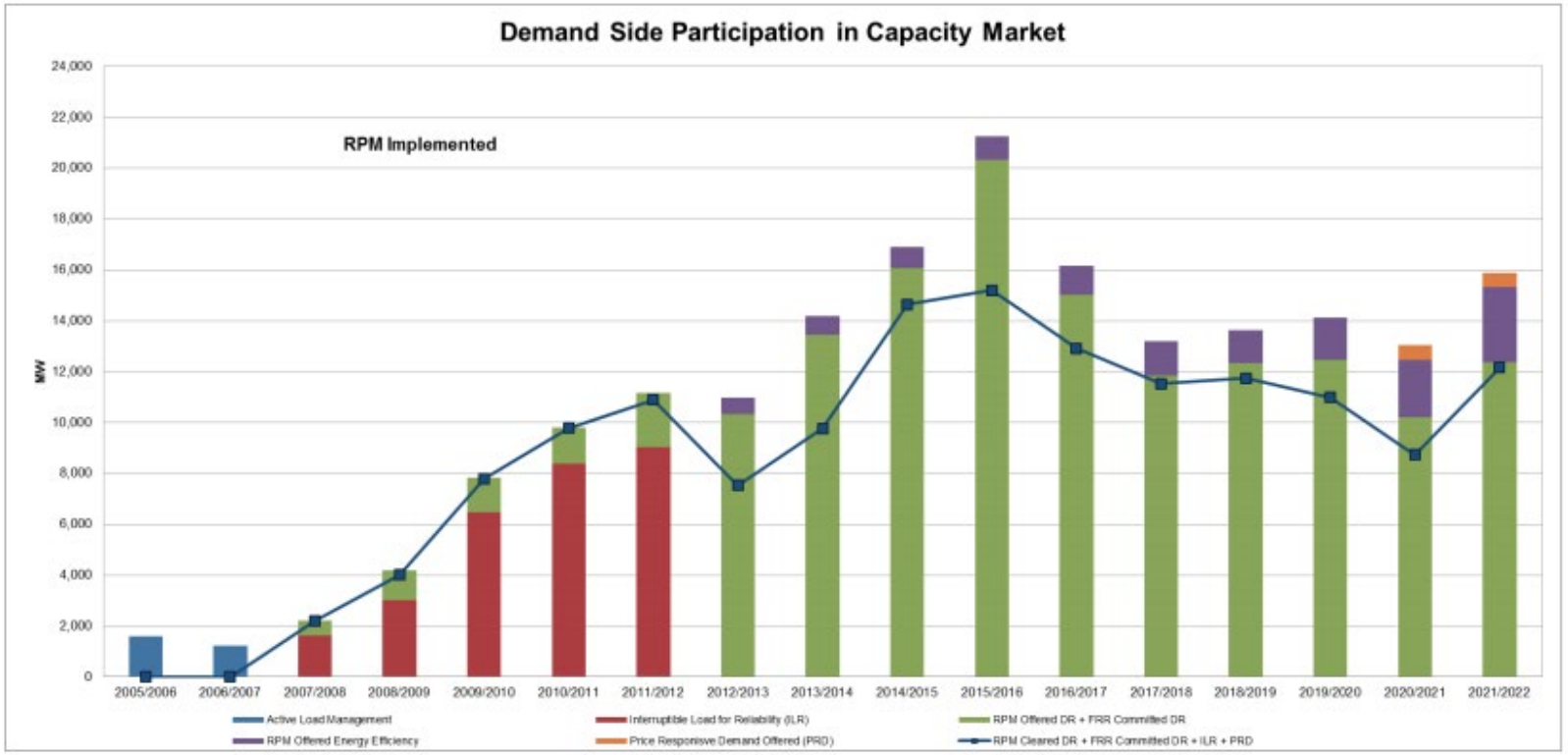
Significant Revenues in Capacity Markets; Less in Energy & Ancillary

Figure 14: PJM Estimated Revenue for Economic and Load Management DR Markets



Source: PJM, *2019 Demand Response Operations Markets Activity Report*

Market Participation Rules Can Erect Barriers to Aggregation



Source: PJM, *2021/2022 RPM Base Residual Auction Results*

Session 8

Lessons Learned from Other State Regulators

Chris Villarreal, President,
Plugged in Strategies

DER Aggregation- Metering, Telemetry, and Data

Missouri Public Service Commission

Informational Workshop for File No. EW-2021-0267

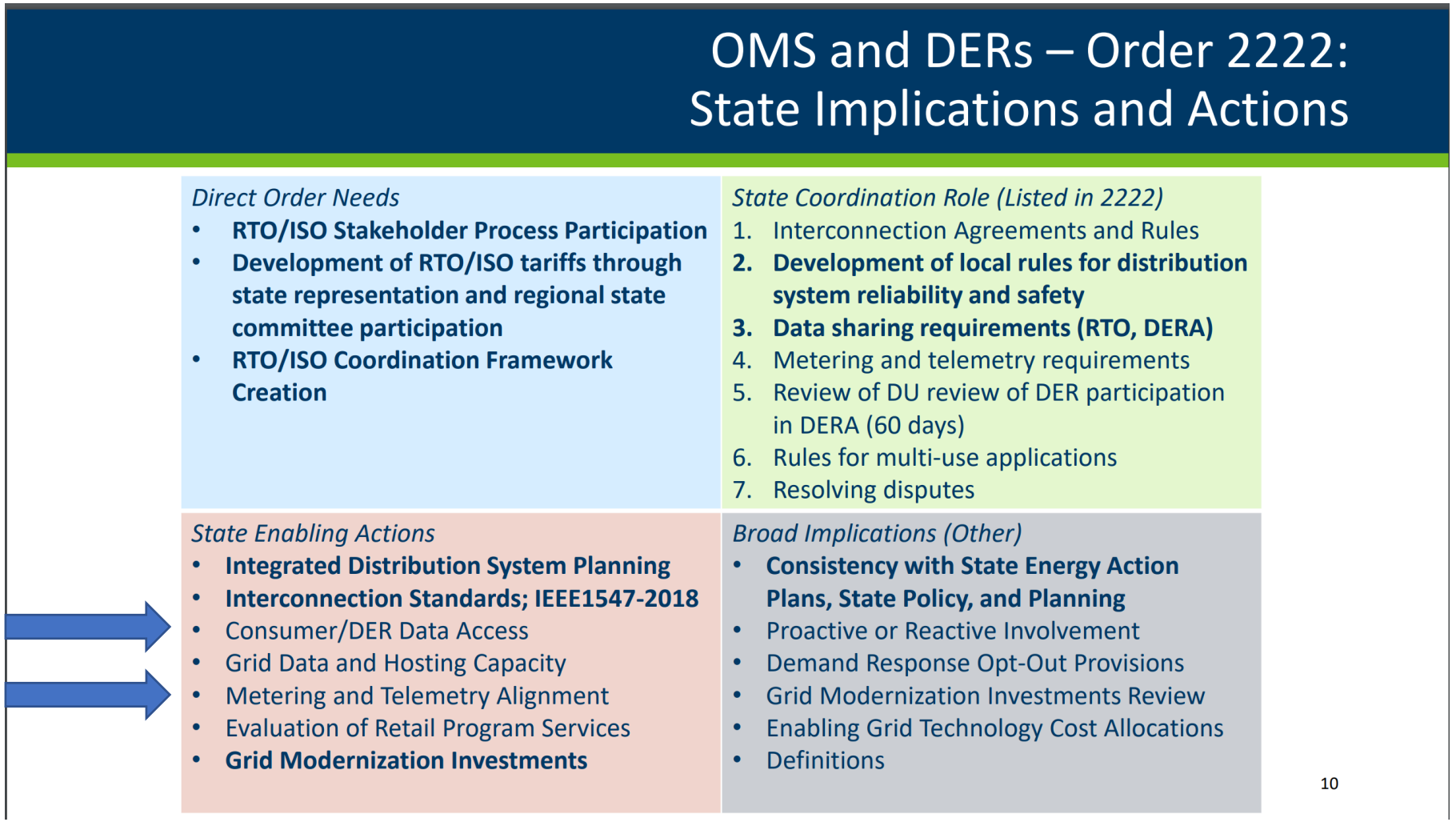
Chris Villarreal, Plugged In Strategies

June 29, 2021

What are the initial challenges for 2222 implementation?

- Coordination framework
- Metering and telemetry
- Access to customer usage data
- RTO Capability
- State responsibility for retail customers
- Repeat of 745 concerns from states and utilities

State Responsibilities



https://cdn.misoenergy.org/20210224%20DER%20DC%20Coordination%20Workshop%20State%20Perspective%20DeBleeckere525584.pdf

Metering and Telemetry

- FERC stated that metering and telemetry requirements should be commensurate with requirements of the product
  - If providing regulation service, aggregator should provide same type of metering and telemetry; if providing non-spin, metering and telemetry should be appropriate for that.
- Aggregators may not have ability to install equipment to have “real-time” visibility, but may use sampling or other methodology.
- Important to identify where metering needs are required- at the premise/technology or somewhere above it?
  - In other words, do aggregators need to provide real-time visibility to the inverter/thermostat or do they need to provide at some node above the technology?
- This is one of the places where utilities/transmission owners may attempt to support unnecessary requirements on DER aggregators.

Needs differ depending on purpose

- Metering/Telemetry/data needs will be different for-
  - Operations
  - Settlement
  - Customer data for aggregator program development and sign-ups
- Operations
  - Need more “real time” visibility
  - Who provides that data?
- Settlement
  - “Settlement quality” data
  - Typically, will come from utility meter (AMI?)
  - Create or extend accuracy standard to other metering-like equipment
- Customer data

Data Access

- 2222 directs RTOs to work with stakeholders and states to identify data needs.
- Includes Customer Energy Usage Data
- For aggregator to provide potential customer savings from a program, meter data necessary to run estimates
- For aggregator to settle in RTO, will need billing data.
- States will need to develop data access policies in order to enable aggregators to participate in RTO markets
- Development of an overall data access framework that applies consistently across jurisdictional utilities lowers barriers to entry for third parties, and ensures a common expectation for data flow and format, and responsibilities

Types of data for 2222 implementation

- Customer-
  - Granular meter data (kwh, kw, volt)
  - Rate information ($/kwh, billing cycle)
  - Address (confirm customer location)
  - Green Button Connect Retail schema
- Grid
  - Hosting capacity
  - Locational details
  - Interconnection
- Technology needs
  - AMI
  - MDMS
  - D-SCADA
  - GIS
  - ADMS

IMPORTANT!
For Green Button Connect implementation, must require that utilities and aggregators are using a “Certified” implementation

What that means

- States have to work with RTOs to develop requirements that work with RTO and state
- States have to develop their own policies and requirements to enable DER participation
  - Develop Data Access policies
  - Develop registration process for aggregators
  - Update interconnection tariffs
- States will also review utility funding for additional investments needed to meet 2222 and RTO tariff requirements
- Ensure consistency across state
  - Standardization is vital: same process, same data, same data format
  - Use modern, internet-based consent models that can be done in as few clicks and pages as possible; no more paper copies to scan and email.

Final Thought

- Commission does not need to wait for RTO action to address customer data access and privacy guidance (or interconnection)
- Items like customer data access and privacy framework (and interconnection updates) are needed even without 2222
- For data access and privacy, several existing models that can inform your process and policy

Questions?

Thank you!

Chris Villarreal
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Session 9

Next Step for MO and Q&A

Moderators: Whitney Payne, Senior Counsel, Missouri Public Service Commission

and

J Luebbert, Associate Engineeer, Missouri Public Service Commission

Registry for DR/DER Aggregators

If it chooses to do so, PSC has several jurisdictional hooks to compel participation in DR/DER Aggregator registry . . .

- As a condition of gaining customer-authorized access to customer meter data from utility for DR/DER settlements at MISO.
- As a condition to participate in any utility program or receive a contract to provide resource adequacy credit to a state jurisdictional utility.
- A third option to opt out decision: a conditional opt in. *'DR aggregators are allowed if they agree to [do whatever the commission requires].'*

NY, PA, CA have a registry and regulation covering DR/DER aggregators.*
VA and MD have a registry and limited regulation.*
Most states have no or little regulation over DR/DER aggregators.

The Bridge to Energy's Future

CPower

Suggestions for a path forward

- Focus on state issues. DER rule implementation issues at MISO will continue, but the MISO issues are not those most important issues for state commissions.*
- States have enough on their plate with important state issues – 1) customer-authorized data access, 2) models to allow aggregators to support utility resource adequacy plans with DR/DERs, 3) interconnection rules, 4) dual participation, 5) distribution system management with DERs, etc.
- Get started. DR is less complicated than other DERs. Allow ARCs to participate in MISO now with DR, at least with Commercial and Industrial customers, in order to gain experience and understanding of the benefits.

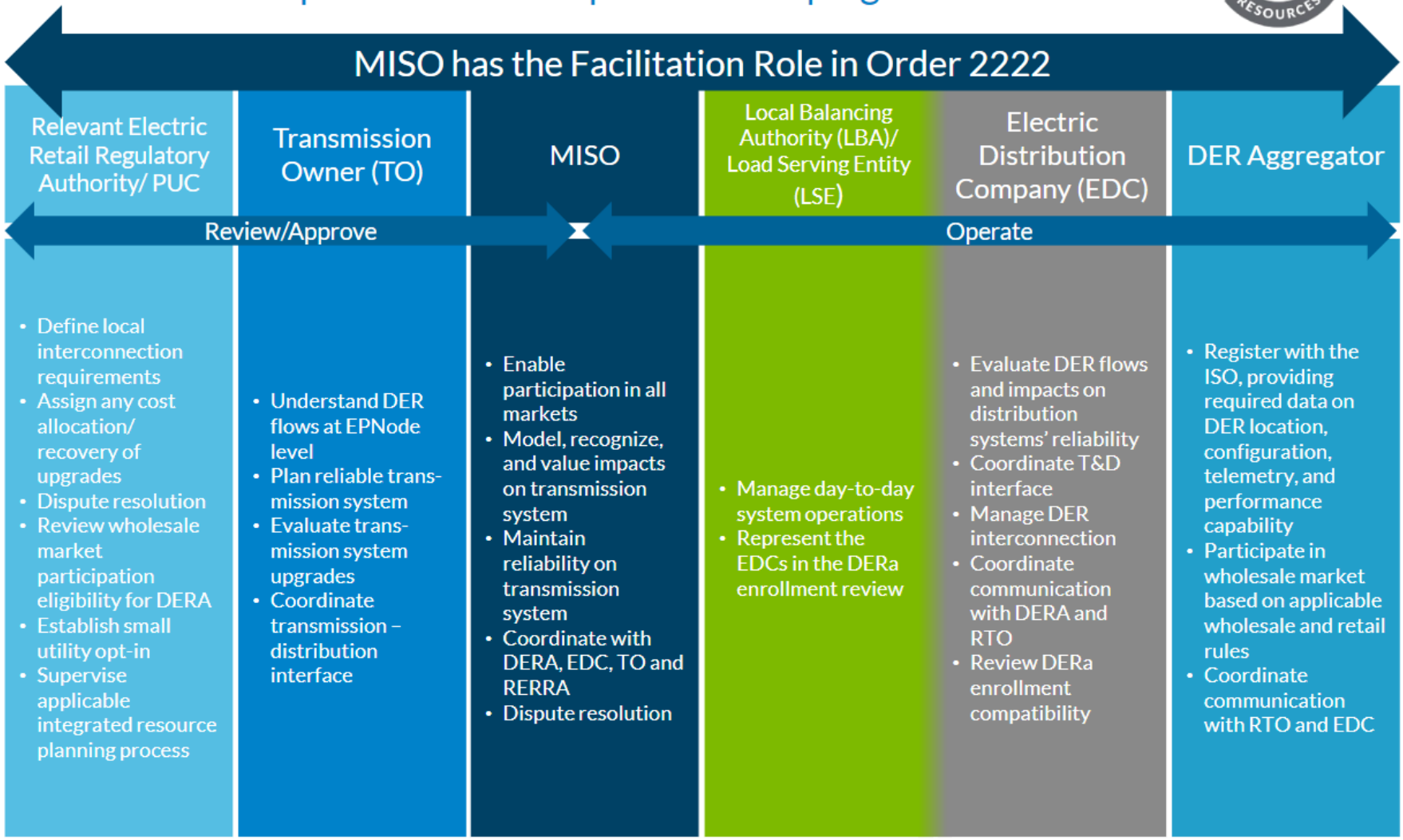
* To be clear, distribution utility capabilities for managing a system with DERs is an important state issue too. Order 2222 is not driving that issue, but rather the rapidly growing deployment of DERs by customers. If anything, DER rule implementation will support distribution system management by giving utilities more information about the activities of DERs participating in MISO's market.

2222 Implementation Assumptions/Questions/Concerns (cont'd)

- Cost recovery expectations must be clearly addressed
  - For any customer locations where enhanced data streams (speed, sourced from customer equipment, etc.) are required to enable customer to participate in MISO markets
  - Cost of building and operating portals to support enrollment
  - Affordability of energy service by non-participating customers
    - Substantial subsidies already provided for generator development through REC programs
  - Enhanced DERMS capability will likely need to be built to both digitally communicate with MISO and ensure distribution system reliability, and will need to support both monitoring and control purposes (DERMS+optimization)
  - Will likely require incremental staffing resources, and new skill-sets

- MISO's aggregation implementation rules need to recognize differing LDC operations/structure/experience in vertically-integrated and restructured states
  - Varying levels of smart meter deployments; existing tariff structures/systems/staffing to support retail DER compensation programs and 3rd party activity, etc.

FERC has called for collaboration across jurisdictions and seams; successful implementation requires developing new frameworks



RERRA Meetings

- **Relevant Electric Retail Regulatory Authorities (RERRAs)** may include state public service commissions, public utility commissions, utility boards, municipal authorities, public power agencies, and cooperative boards – any regulatory entity responsible for setting electric retail rates. This term is used throughout Order 2222 and is a typical term in FERC-created documents.

- **July 28 (2-4PM EST)** meeting with RERRAs: This session, open to all, is planned as part of our O2222 coordination framework to speak to the specific concerns of regulators in the MISO footprint as we look at DERA participation in MISO markets. Outside of standard DER TF participation, this meeting, and subsequent RERRA sessions, will be the primary method by which MISO will reach out to RERRAs regarding O2222 coordination. A pre- and post-session survey will be sent to the RERRAs with the opportunity to provide comments on RERRA-coordination needs.

- Future RERRA/MISO sessions are planned for **October 2021 and February 2022**.