Order 2222 Design Full Proposal

PJM Staff
DIRS
November 2021

- Proposal updates addressing Order 2222 Directives and Order 2222A and Order 2222B clarifications and updates.
- PJM presentations and overviews linked here:
  - Order 2222
  - Order 2222A
  - Order 2222B

Order 2222 Compliance Directives

- Allow DER aggregations to participate directly in RTO/ISO markets, and establish DER aggregators as a type of market participant (130);
- Allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations (130);
- Establish a minimum size requirement for DER aggregations that does not exceed 100 kW (171);
- Establish locational requirements for DER aggregations that are as geographically broad as technically feasible (204);
- Address distribution factors and bidding parameters for DER aggregations (225);

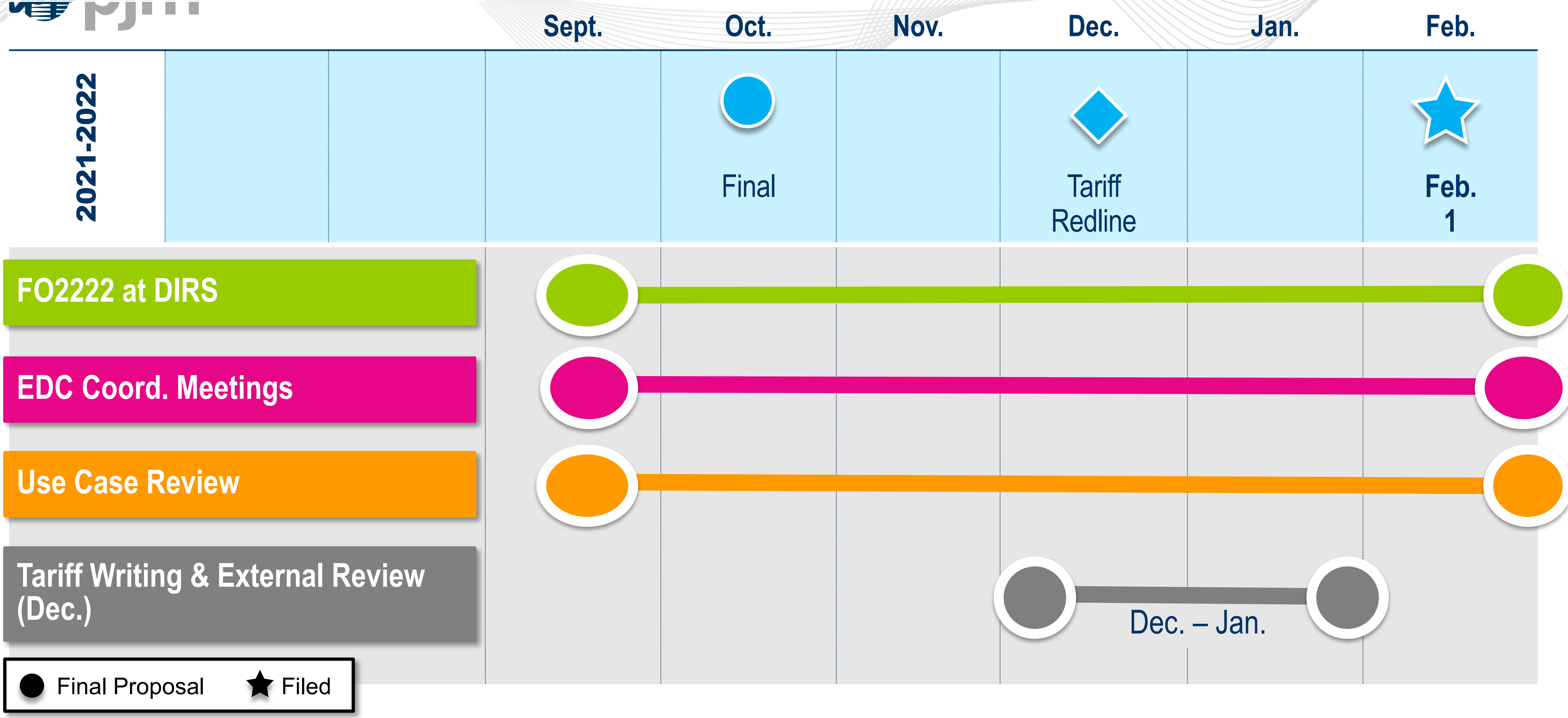
Order 2222 Compliance Directives

- Address information and data requirements for DER aggregations (236);
- Address metering and telemetry hardware and software requirements for DER aggregations (262);
- Address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities (”RERRA”) (278);
- Address modifications to the list of resources in a DER aggregation (335); and
- Address market participation agreements for DER aggregators via adoption of a standard market participation agreement for DER aggregations (352).

- FERC Grants Order No. 2222 Extension for PJM, and accordingly the new due date of PJM's Order No. 2222 compliance filing is February 1, 2022.

- PJM to provided an informational filing containing a detailed stakeholder process schedule on May 10, 2021 and a status update August 9, 2021.
  – PJM will status reports every 90 days thereafter until the date that PJM submits its compliance filing.

Timeline


Sept.
Oct.
Nov.
Dec.
Jan.
Feb.
2021-2022
Final
Tariff Redline
Feb. 1
FO2222 at DIRS
EDC Coord. Meetings
Use Case Review
Tariff Writing & External Review (Dec.)
Dec. – Jan.
Final Proposal
Filed

- Expected implementation date a few years after filing (2025/2026), or earlier if possible
- Factors impacting implementation date:
  - FERC is in an FPA 206 posture, so FERC (not PJM) will ultimately set the effective date.
  - PJM will wait for FERC order before working on implementation. Order 2222 is a large filing, not a given FERC will approve as filed
  - Changes needed to DA and RT engines, Markets Gateway changes, new or updated database/system for registrations information, updated planning, operations and markets procedures
  - Existing market software upgrade (nGEM) implementation timeline
  - RERRA readiness for DER Aggregation market participation

PJM Guiding principles for design development

- Compliance with FERC Order 2222 and 2222-A
- Remove barrier for market entry for DERs
- Uphold parity between models where applicable
- Maintain or enhance system reliability
- Simple implementation to evolve over time
  - Propose “check-in” point to re-evaluate part(s) of the design
  - Be able to accommodate and build out with DER operations into the future

Terminology- PJM Tariff

- **“DER Aggregator”** shall mean an entity that is both a Member and a Market Participant, that uses one or more DER Aggregations to: (i) participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model; and (ii) has a fully-executed DER Aggregator Participation Service Agreement.
- **“DER Aggregation”** shall mean one or more DER Aggregation Resources. A DER Aggregation is capable of satisfying a minimum market offer of 100 kW.
- **“DER Capacity Aggregation”** shall mean a DER Aggregation that participates in the Reliability Pricing Model, or is otherwise treated as capacity in PJM’s markets, such as through a Fixed Resource Requirement Capacity Plan.
- **“DER Aggregation Resource”** shall mean any resource, within the PJM Region, that is located on a distribution system, any subsystem thereof, or behind a customer meter, and is used in a DER Aggregation by a DER Aggregator to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model.
- **“DER Aggregator Participation Model”** shall mean the participation model accepted by the Commission in Docket No. ER22-___-000.

Order 2222 Design

DERA Jurisdiction & Interconnection

1. Interconnection
2. Market Participation Agreements
3. Opt-in for Small Utilities

Operations

1. Locational Requirements
2. Distribution Factors
3. Telemetry
4. Operational Needs

Market Design

1. Market Participation Model
2. Type of Technology (Homogenous / Heterogeneous)
3. Bidding Parameters
4. Min./Max. Size Requirements

Settlements

1. Metering Configuration
2. Settlement requirements
3. Double Counting Services
4. Use case development

Coordination

1. DER Registration
2. EDC Coordination
3. Modification to List of Resources

DERA Jurisdiction & Interconnection	
Interconnection	• PJM will not have jurisdiction of the interconnection of DER resources • DER owners will utilize the applicable state interconnection process without entering the PJM queue, if solely participating in a DERA provided a number of criteria are met
PJM Planning Requirements	• Data Requirements for Planning defined for necessary PJM study and reliability
Opt-in for Small Utilities	• Opt-in process for small utilities • Opt-out (large utilities) and opt-in (small utilities) requirements of Order Nos. 719 and 719-A still apply for Demand Response resources.
Market Participation Agreement	• Attestation that DERA is compliant with tariffs/operating procedures/rules of distribution utility and RERRA • Reviewing parties to Market Participation Agreement

- FERC makes clear in the Order that DER engaging in wholesale market activity through a DER Aggregation do not fall under a Commission-jurisdictional interconnection, stating the following:

- *We decline to exercise jurisdiction over the interconnections of distributed energy resources to distribution facilities for those distributed energy resources that seek to participate in RTO/ISO markets exclusively as part of a distributed energy resource aggregation. As such, only a distributed energy resource requesting interconnection to the distribution facility for the purpose of directly engaging in wholesale transactions (i.e., not through a distributed energy resource aggregation) would create a "first use" and any subsequent distributed energy resource interconnecting for the purpose of directly engaging in wholesale transactions would be considered a Commission-jurisdictional interconnection. (96-97)*

Interconnection

- PJM will not have jurisdiction of the interconnection of DER resources; however, a coordinated study including modeling must be provided for any delivery point where power injections can or have occurred prior to entering a DERA agreement.
- PJM will have oversight over the DER aggregation (DERA) participating in PJM markets.
- DER owners will utilize the applicable state interconnection process without entering the PJM queue, if solely participating in a DERA provided a number of criteria are met:
  - The DER satisfies the state interconnection requirements to interconnect
  - The DER satisfies any other applicable requirements to be eligible to participate in PJM's wholesale market in a DERA.
  - The impact of DER interconnected solely through state interconnection processes can be adequately represented in PJM power flow models for transmission planning purposes.
  - DER has a signed Interconnection Agreement with the applicable utility.

- If a DER does not satisfy the requirements for DERA participation, this resource will need to enter the PJM queue and be studied by PJM.
  - This DER will not be allowed to participate in a DERA and will be required to participate in PJM markets as a stand-alone resource.

- All resources will still have the opportunity of going through the queue, if they choose, or if a state interconnection process is unavailable.
  - These resources will not participate under the Order 2222 DERA model.

- Resources participating in a DERA, will not receive Capacity Interconnection Rights (CIRs) from PJM. However, those resources may be able to participate in the PJM Capacity Market through a nominated Capacity value for a DERA.

- DERs that successfully register with PJM as part of a DERA and receive a capacity value will retain their capacity accreditation, subject to having a valid State IA.

- With the integration of DERs participating in PJM Markets, PJM's transmission planning and RTEP process is currently being reviewed for any necessary updates to accommodate the DERs. Below are initial positions:

Status Quo for retail connected BTM DERs

- Current modeling represents DER activity on distribution as a reduction to load in the transmission models.
- Netted model may be sufficient for low levels of DER participation but will be inadequate if DERA spurs growth as intended by Order 2222.

Concerns with expanded DER participation and continued use of netted generation model

- Netted generation and loads are not visible to PJM's Planning analyses;
  - Generation and load have different characteristics;
  - Differences impact load flow analyses;
- Introduces reliability risks in scenarios where PJM must serve load

Concerns with expanded DER participation and continued use of netted generation model

- NERC has issued several recent recommendations against netting; for example:
  - Reliability Guideline: Model Verification of Aggregate DER Models in Planning Studies (March 2021)
  - Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies (September 2020)

Proposed Data Requirements for Planning

- For each DER within a DER aggregation provided with the DER registration:
  - Address
  - Technology (solar, battery, landfill gas, wind, hybrid, etc.)
  - Maximum AC output (gross nameplate capability)
  - ~~Interconnected distribution line identification~~
    - ~~PJM plans to track distribution location and work with Transmission Owner to update transmission model, as necessary (Quality Assurance).~~
  - PJM Planning Model Bus ID that the DER aggregation ~~distribution line~~ is fed from*
  - Ride through capability enabled? Y/N
  - Voltage control enabled? Y/N
- Both Aggregator and Electric Distribution Company will verify data annually

*EDC will coordinate with the TO to provide PJM Planning model updates.

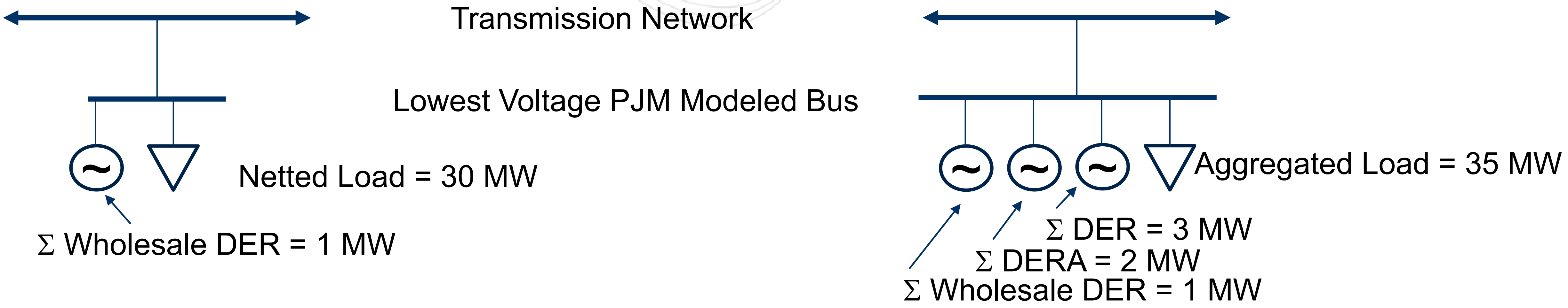
Annual Verification of DER Aggregation Modeling

- On an annual basis, or sooner if necessary based on frequency of model changes, Transmission Owners will verify the accurate modeling of the DERs and DER aggregations on their systems and ensure they are consistent with DERs interconnected to the distribution systems served.
- The annual verification of the DER aggregate data will consist of reviewing and updating the amount of MWs, the fuel type, the participation type for each DER aggregation as well as any distribution system changes that may impact the planning model bus that the DER aggregations are fed from.
- The annual verification would confirm that any DERs in the model that are considered Behind the Meter Generation (BTMG), and modeled as such, satisfy the PJM rules for BTMG or non-retail BTMG.

Simplified Example of Netted and Aggregated Modeling

Netted (current method)

Aggregated (proposed method)



Modeling Goal:

For any circuit with aggregate (non-wholesale DER) generation > 1MW, Transmission Owners will provide:

- aggregate load explicitly;
- aggregate DER generation explicitly (by fuel type);
- aggregate DERA participants explicitly separately (by fuel/participation type); and
- contingencies where combined aggregate DERA and DER generation ≥ 5 MW, and any aggregate load, can transfer to a different transmission bus.

Justification for Planning Data

- Provides better visibility of load and generation for PJM Planning;
- Improves PJM planning studies and transparency;
- Information should be readily available from participants; and
- Aids PJM in aligning with NERC and industry guidelines.

Jurisdiction

- Market-Based Rate Authority?
  - DER Aggregators intending to sell energy, capacity, or ancillary services at market-based rates will likely need Market-Based Rate Authority. (2222, n 94)
    - DER Aggregators should consult with their respective FERC counsel.
  - Order 2222 will not require individual DERs within an aggregation to have Market-Based Rate Authority.

- PJM Members?
  - DER Aggregator will need to be a PJM member to operate in PJM Markets.
    - DER physical owners will <u>not</u> need PJM membership.
  - DER Aggregator will be subject to credit requirements, based on the markets they are participating

- DERs NERC Registered?
  - Unlikely - does not meet the 75MVA threshold or the 100kV connection threshold (NERC ROP, Appendices 2 & 5B).
    - Questions should be referred to DER Aggregator's FERC counsel regarding specific configurations.
  - This could change based on specific resources and further NERC advancement in DER activities.

- *Pro forma* agreement under the Tariff
- PJM, ~~Utility,~~ and Aggregator are party to agreement
- Attestation that DERA is compliant with tariffs/operating procedures/rules of distribution utility and RERRA.
- Draft market participation agreement with meeting materials (10/26)

Dispute Resolution

Dispute *working details for discussion	Disputing Party	Adjudicated by FERC	Adjudicated by States
Market Entry for DERA - denied	DER Aggregator	X	
Market Entry for DERA – approved	Utility	X	
Override for reliability, safety, or other needs by utility, resulting in Market penalty for DERA	DER Aggregator		X
Override, choice of assets to curtail by utility, resulting in Market penalty for DERA	DER Aggregator		X
Compensation to DERs from DER Aggregator	DER Owners		X
Inaccurate Market compensation or data submission discrepancy	DER Aggregator	X	
Retail/Wholesale double counting – denied participation in PJM Market(s)	DER Aggregator	X	X
Retail/Wholesale double counting – approved participation in PJM Market(s)	Utility	X	X
PJM planning upgrades due to DER penetration	Load	X	

- *Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and do not accept bids from DER aggregators if its aggregation includes DERs that are customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the RERRA permits.*

- The opt-out (large utilities) and opt-in (small utilities) requirements of Order Nos. 719 and 719-A still apply for Demand Response resources.

Opt-In Small Utility

- DR Opt-in/Opt-out process would apply to the following resources
  - Demand Response (load curtailment) resources
  - Resources participating with load curtailment and FTM injections in PJM Markets
    - Existing process for these resource in Demand Response
- Order 2222 Opt-in process would apply to the following resources:
  - FTM generator, energy storage, and energy efficiency resources
- Transition period to be proposed for small utilities that do not opt-in and transition to a large utility (utilities that distributed more than 4 million MWh).

Operations	
Locational Requirements	• Nodal model to align with PJM dispatch and pricing • Primary location node will be identified in PJM system • All DER primarily maps to same node to aggregate to a DERA
Distribution Factors	• Distribution Factors Or "weighting factors" will not be used in initial implementation
Telemetry	• Telemetry will be required at the aggregation level • All capacity and ancillary service DERA >=0.1MW, and all energy only DERA >=10MW will provide PJM telemetry • Scan rate for energy and reserves = 1minute, regulation 2/10second
Cyber Security	• PJM will implement cyber security at PJM's "first hop" • Additional cyber security needed
Outage Reporting	• Outage reporting will be required for DERAs in capacity market

Operations

From FO2222

- *Establish locational requirements for DER aggregations that are as geographically broad as technically feasible (204);*

- Takeaways from previous discussions:
  - Concerns around transmission constraint control and accurate LMP formation with geographically broad aggregations
  - Operational concerns on distribution system with broad aggregations; especially across utility footprints
  - Improved market entry and lower chance of underperformance with broad aggregations for DERAs

Locational Requirements

- What do locational requirements define for DERAs?
  - Locational requirements as discussed in this section will define how DERAs are modeled and dispatched for Energy & Ancillary Services.
    - These locational requirements will not necessarily define Capacity participation or Ancillary Service performance evaluations or Ancillary Only aggregations.
- Each DER to be identified and mapped in the PJM network model
  - The location of each DER will be based on electrical impact and determined during the DERA registration process
- Each DER in a DERA will need to be at the same primary location
  - Weighting Factors will not be required from DERA in this model

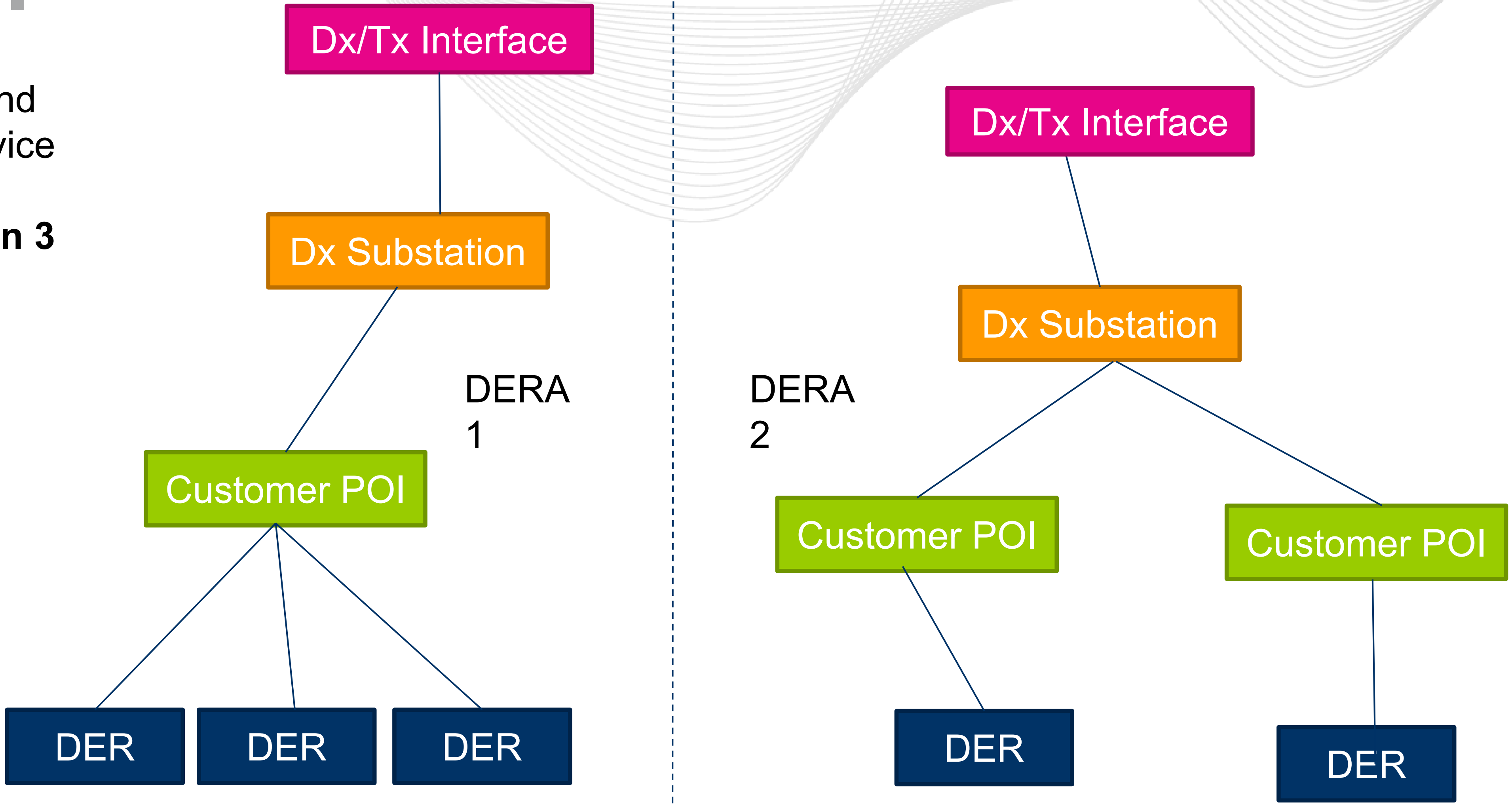
From FO2222

- to the extent that RTOs/ISOs ***allow for multi-node distributed energy resource aggregations, distribution factors and bidding parameters should provide the RTOs/ISOs with the information*** from geographically dispersed resources in a distributed energy resource aggregation necessary to reliably operate their systems regardless of the size of the aggregation We also note that, given our findings on locational requirements, we are not requiring RTOs/ISOs to establish multi-node distributed energy resource aggregations (174)
- we require each RTO/ISO ***that allows multi-node aggregations to revise its tariff to (1) require that distributed energy resource aggregators give to the RTO/ISO the total distributed energy resource aggregation response that would be provided from each pricing node,*** where applicable, when they initially register their aggregation and to update these distribution factors if they change; (225)

- Distribution Factors will not be required for PJM’s initial implementation of DER Aggregations
  – Referred to as “weighting factors” in PJM proposal
  – Given we are using a “single location” approach, we will not require weighting factors for initial implementation.
  – Exploration of distribution factors and complexity will be continue to be explored past implementation for potential future use.

Locational Requirements

For Energy and Ancillary Service Participation
Configuration 3 - Two DERA

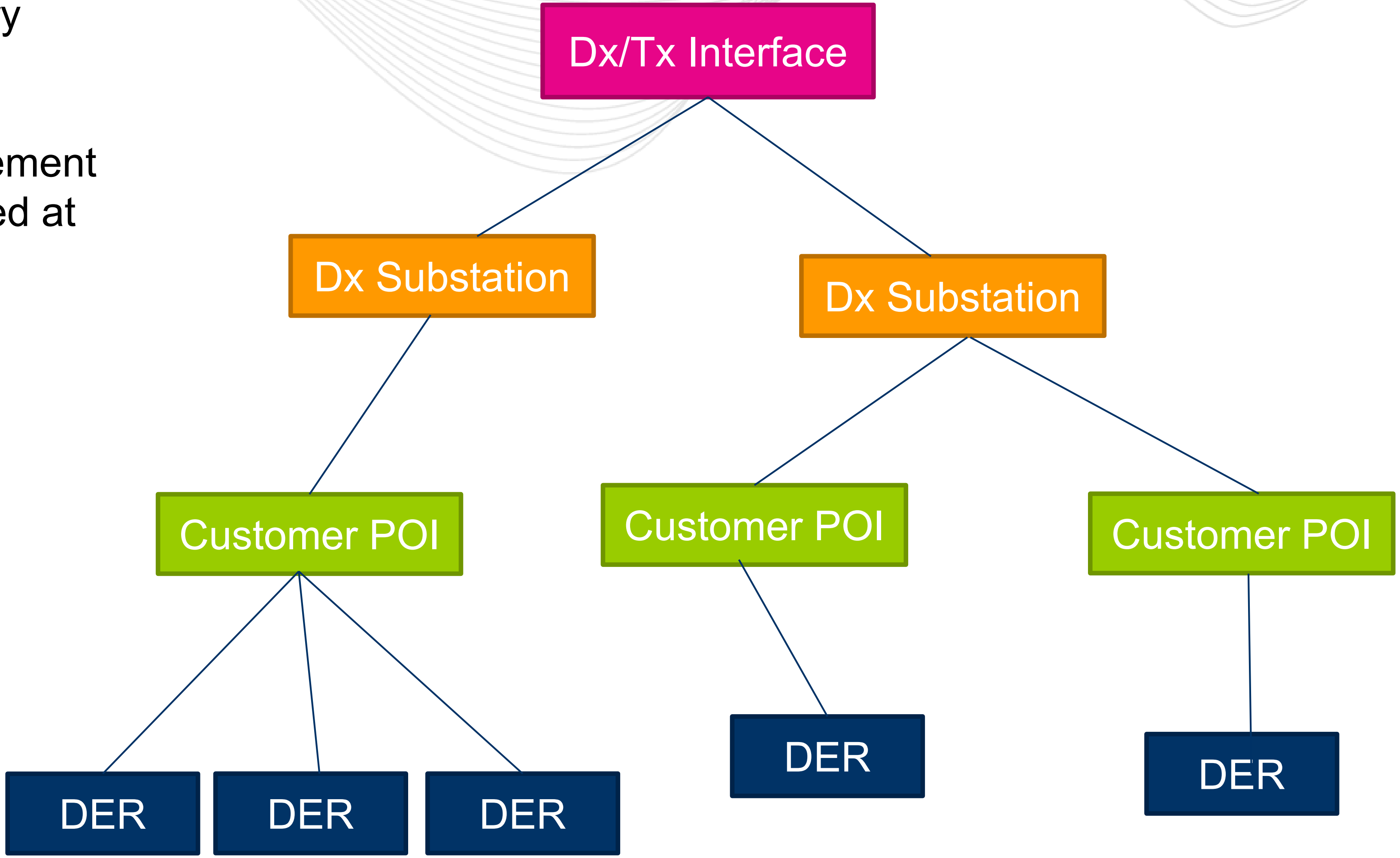


Locational Requirements

For Energy and Ancillary Service Participation

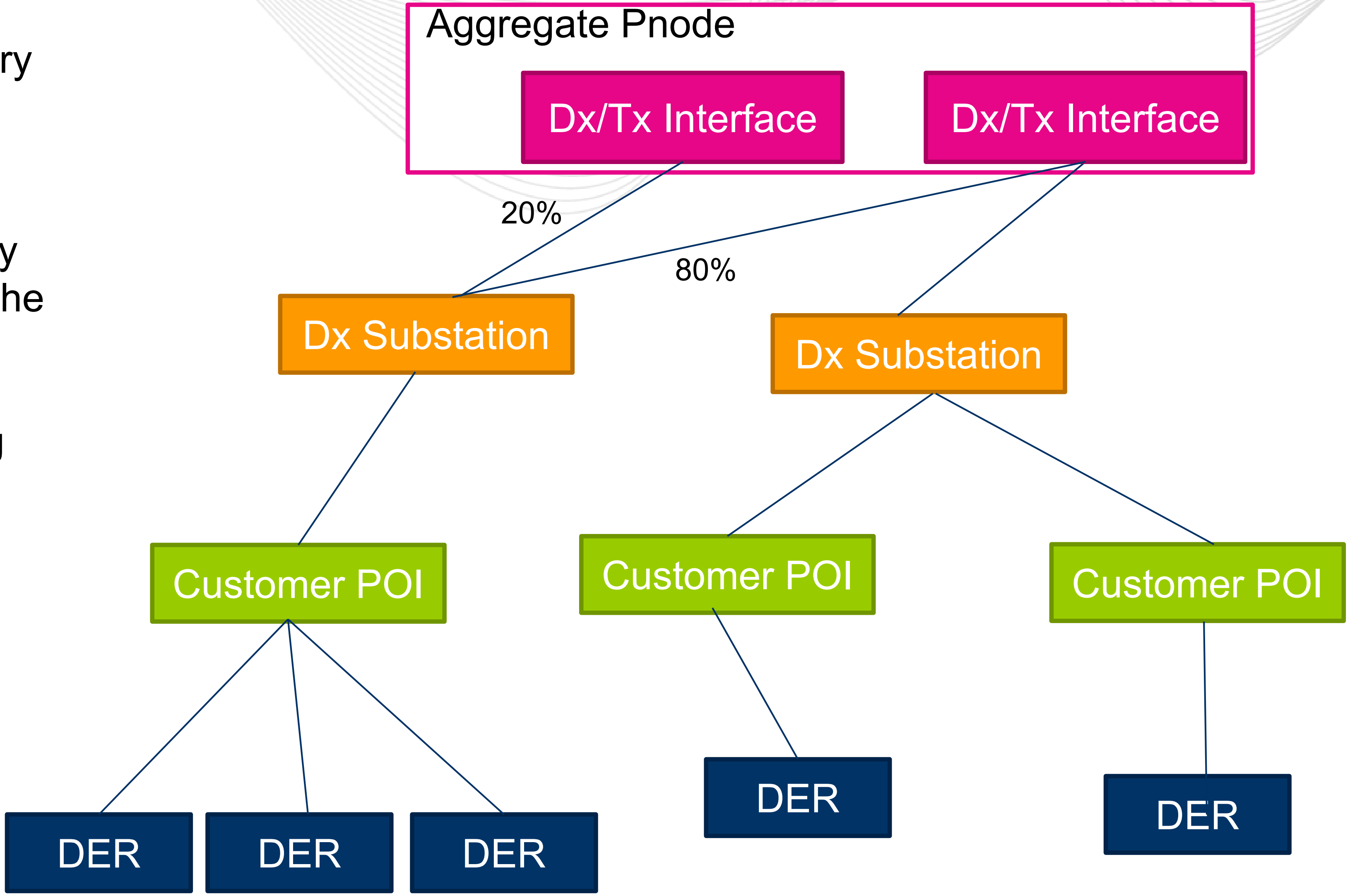
Configuration 1

- Single location requirement (primary node) evaluated at the Dx/Tx Interface
- One DERA
- Priced at pnode



For Energy and Ancillary Service Participation
Configuration 2

- Single location requirement (primary node) evaluated at the Dx/Tx Interface
- One DERA
- Split Nodal Mapping
- Priced at aggregate Pnode



All the "Factors"

- (inputs/registration) **Capability Factors** (At DER level)
  - PJM will determine a capability factor, based on nameplate of DERs in a DERA. These will not be updated unless the aggregation changes and it is reviewed and approved by PJM/EDC.
- (inputs/registration) **Locational Factors** (At the DER level)
  - This is the mapping that the EDC/Aggregator provides for transmission location(s) (all DERs in aggregation sharing primary node), during registration process. This will not be updated unless reviewed and approved by PJM/EDC.
- (operations/markets) **Modeling Impact Factor** (At the DERA level)
  - The factor to be used in pricing/dispatch. It will be calculated from the capability factor and locational factor. There will not be a dynamic update of this value (hourly/daily) but can change over time if DERA changes occur (via registration process).
- (operations/markets) **Weighting Factors** (AKA "distribution factors" from Order 2222)
  - Defined as the breakdown of which DERs are responding to the dispatch signal – would be a RT update from the aggregator. Order ties this to multi-nodal aggregations.
  - Given we are using a "single location" approach, we will **not require weighting factors** for initial implementation.

Single Location Requirements

Registration – Managing Nodal Aggregations

DER	(Utility Review) Primary tranx. location	Size (MW)	Aggregation Definition	(Capability Factor) PJM calculated based on Size & DERA	(Locational Factor) Additional data from EDCs for modeling
DER1	Location 1	1	DERA 1	0.25	100% Node A
DER2	Location 1	1	DERA 1	0.25	100% Node A
DER3	Location 1	1	DERA 1	0.25	80% Node A, 20% Node B
DER4	Location 1	1	DERA 1	0.25	70% Node A, 30% Node D
DER5	Location 2	1	DERA 2	1	70% Node B, 30% Node A
DER6	Location 3	1	DERA 3	1	100% Node C

Operations

Defining Modeling Impact Factors

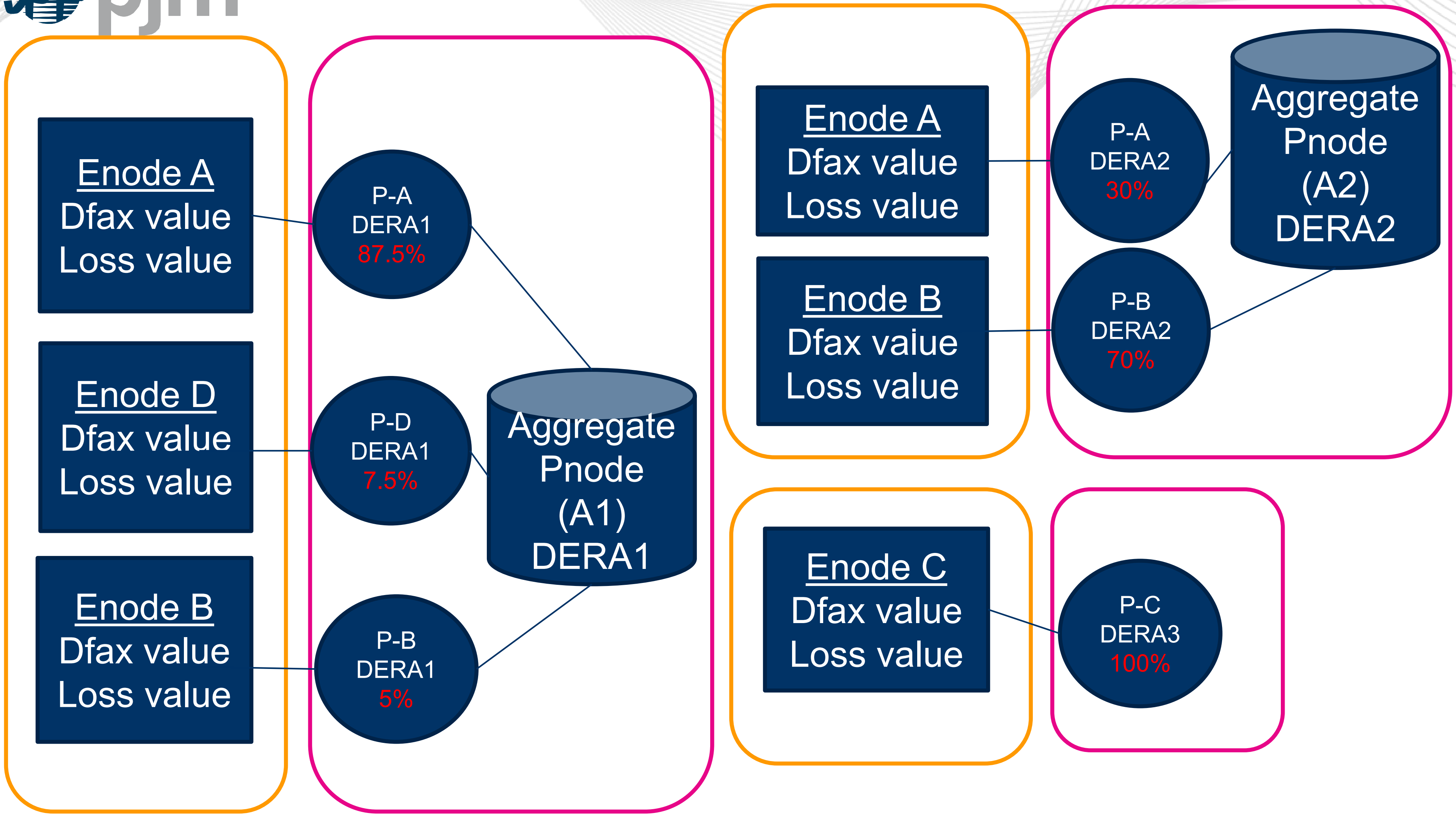
DER	Capability Factor	Aggregation Definition	Locational Factors	Modeling Impact Factors
DER1	0.25	DERA 1	100% Node A	0.25 – node A
DER2	0.25	DERA 1	100% Node A	0.25 – node A
DER3	0.25	DERA 1	80% Node A 20% Node B	0.20 – node A 0.05 – node B
DER4	0.25	DERA 1	70% Node A 30% Node D	0.175 – node A 0.075 – node D
DER5	1	DERA 2	70% Node B 30% Node A	0.70 – node B 0.30 – node A
DER6	1	DERA 3	100% Node C	1.0 – node C

DERA 1
0.875 – Node A
0.050 – Node B
0.075 – Node D

DERA 2
0.70 – Node B
0.30 – Node A

DERA 3
1.0 – Node C

Modeling Impact Factors – Implementation



- DERA locational requirements are single location or nodal
  - All DERs must map to 1 primary location
- Dispatch engine model is multi-nodal pricing (similar to combined cycles) when DERA is mapped to more than 1 node for proper operational modeling

Roles and Responsibilities

Data	Provided By?	Verified By?	When?
Capability/ Size (MW)	Aggregator	Utility	Registration
Capability Factor	PJM	PJM	Registration
Primary Location	Aggregator	Utility	Registration
Locational Factors	Utility	PJM/Utility	Registration
Modeling Impact Factors	PJM	PJM	After Registration
Weighting Factors	N/A	N/A	N/A

Proposal : No use of weighting factors provided in RT by aggregator to represent the operations/dispatch of underlying DERs in a DERA.

Locational Requirements – Why not multi-nodal?

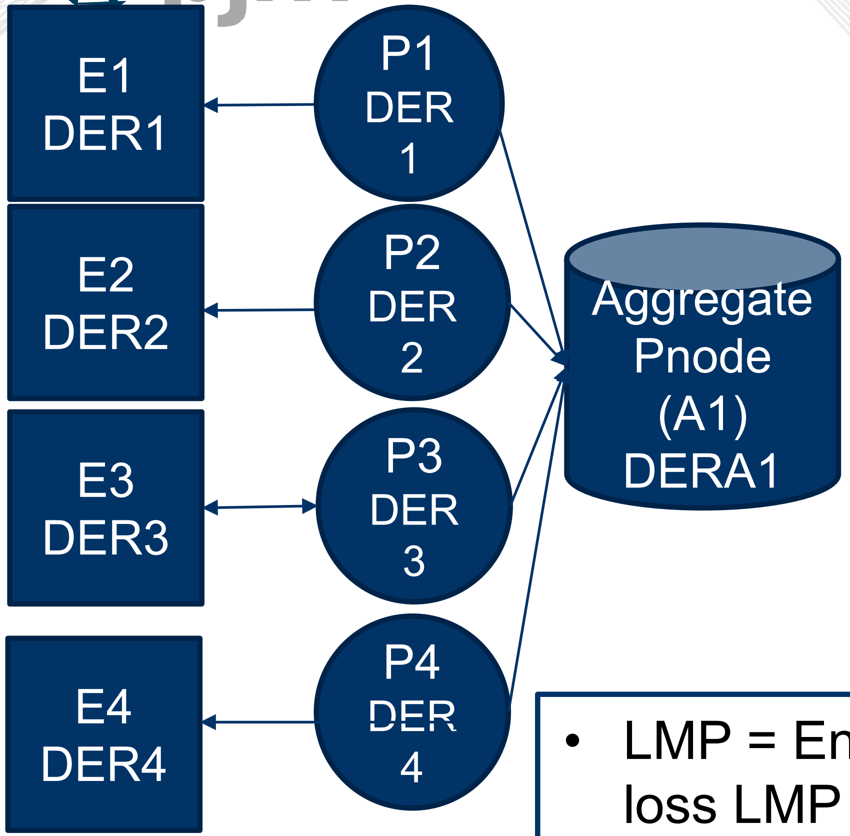
Definitions:

- **Enode =** A modelled electrical node in the PJM EMS model. An enode (or multiple enodes) can map to a pnode in Markets.
- **Pnode =** A pricing node in market model where an energy price (LMP) is calculated, pnode pricing data is available on Data miner 2.
- **Weight =** the portion of MWs that are coming from a specific DER/location within an aggregation. Summation of weight across an aggregation = 1.
- **Dfax =** Distribution factor representing the impact on a constraint for moving generation at that location. A negative value represents a raise-help to the constraint (increase generation helps to alleviate constraint) and a positive value is a lower-help (decrease in generation helps to alleviate constraints).

Locational Requirements - Introduction

- Assumptions:
  - Unlimited ramp capability and DERs will be on at full capacity or off at 0MW
  - Each DER has $20 cost to run
  - All DERs are mapped individually in EMS – based on electrical impact DERAs will be formed with 1 or more of the mapped DERs for Market Participation
- LMP = Energy LMP + sum of congestion LMP + loss LMP
  - Energy LMP = $25; Constraint binds at shadow price of -500; Loss LMP = 0
- Dfax for each node in example was taken from actual location(s) and constraint on PJM system.
  - These locations were close geographically.

Locational Requirements – Why not multi-nodal?



DER	Weight	Enode	dfax	LMP (pnode)
1	0.4	1	-0.468	$259
2	0.3	2	0.093	$-21.50
3	0.2	3	-0.145	$97.50
4	0.1	4	0.006	$22

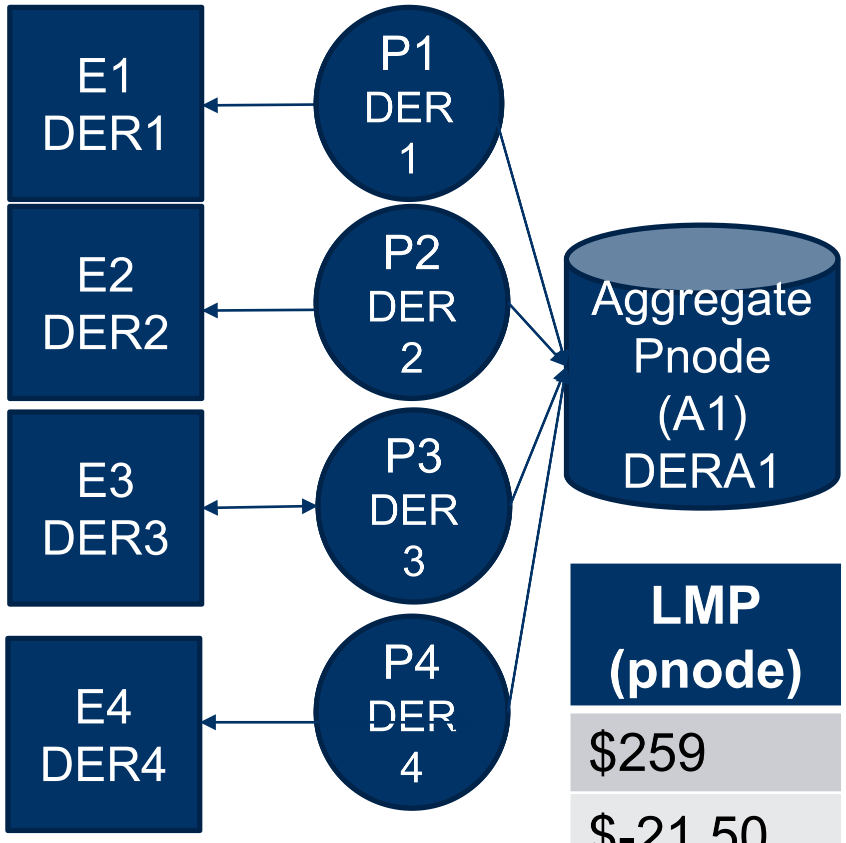
Aggregate A1 dfax = (0.4*-0.468)
+(0.3*0.093)+(0.2*-0.145)+(0.1*.006)
=(-0.1872+0.0279+(-.029)+0.0006)
= -0.1877

- LMP = Energy LMP + sum of congestion LMP + loss LMP
  - Energy LMP = $25, Constraint shadow price =-500, Loss LMP = 0
- A1 LMP = $25+(-0.1877 *-500) + 0
- A1 LMP = $25+$93.85 + 0
- A1 LMP = $118.85
- Dispatch of DERA (A1) = 1MW

- Creating an aggregate Pnode for multi-nodal aggregations will allow dispatch and pricing to capture only the resources in the aggregate
- Dispatch and pricing across nodes creates less accurate results.
  - DER2 would be dispatched to ecomax even though they are located at a negative LMP node. However, aggregate would be dispatched (as a whole) as a net help to the constraint.

Operations

Locational Requirements – Why not multi-nodal?



LMP (pnode)
$259
$-21.50
$97.50
$22

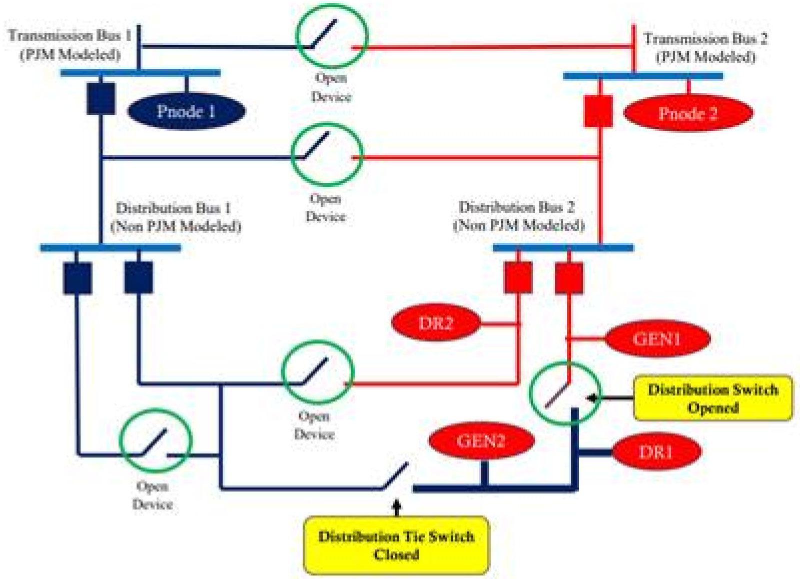
Day-Ahead	Real-Time
Weighting	Weighting
DER1 = 0.4	DER1 = 1
DER2 = 0.3	DER2 = 0
DER3 = 0.2	DER3 = 0
DER4 = 0.1	DER4 = 0
LMP = $118.85	LMP = $259

- Same MWs from the DERA, with different pricing dependent on weighting factors
- Example assumes same conditions in DA and RT

- Locational modeling can be updated but not intended to be dynamic on an hourly/daily basis
  - Modeling will be done on “normal” distribution configurations
    - Capturing dynamic updates in real-time for distribution system is unattainable
  - This will not impact DERA market participation and small inaccuracies may exist based on distribution switching
  - Long term changes will be addressed with a modeling update
    - PJM will update mapping when provided by the utility
    - No less than a yearly review on locational mapping accuracy

Operational Changes

USE CASE 1: DISTRIBUTION TRANSFER



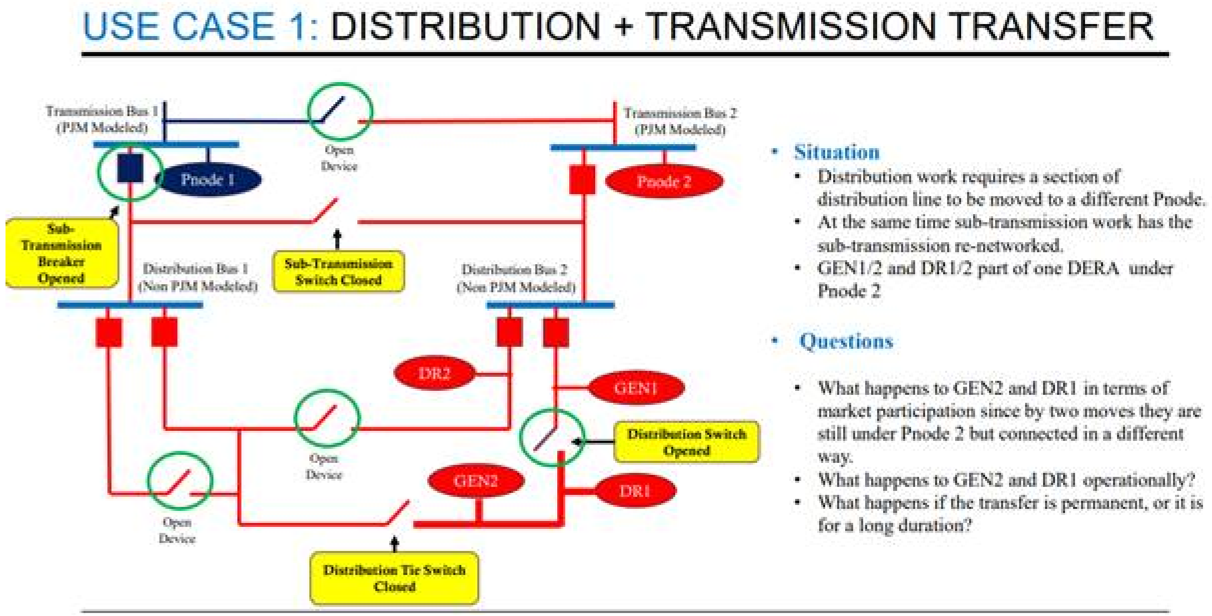
- **Situation**
  - Distribution work requires a section of distribution line to be moved to a different Pnode
  - GEN1/2 and DR1/2 part of one DERA under Pnode 2
- **Questions**
  - What happens to GEN2 and DR1 in terms of market participation?
  - What happens to GEN2 and DR1 operationally?
  - What happens if the transfer is permanent or for a long duration?

- **Market Participation:** DERA would still be able to participate at Pnode 2, even though flows would go over Pnode 1 and 2.

- **Operations:** DERA still able to participate in PJM. If EDC in unable to allow these resources to safely operate due to switching they should perform over-rides.

- **What happens if the transfer is permanent or for a long duration?** Modeling will be updated to reflect new "normal" distribution flows. This may result is splitting the DERA if locational requirements are no longer met

Operational Changes

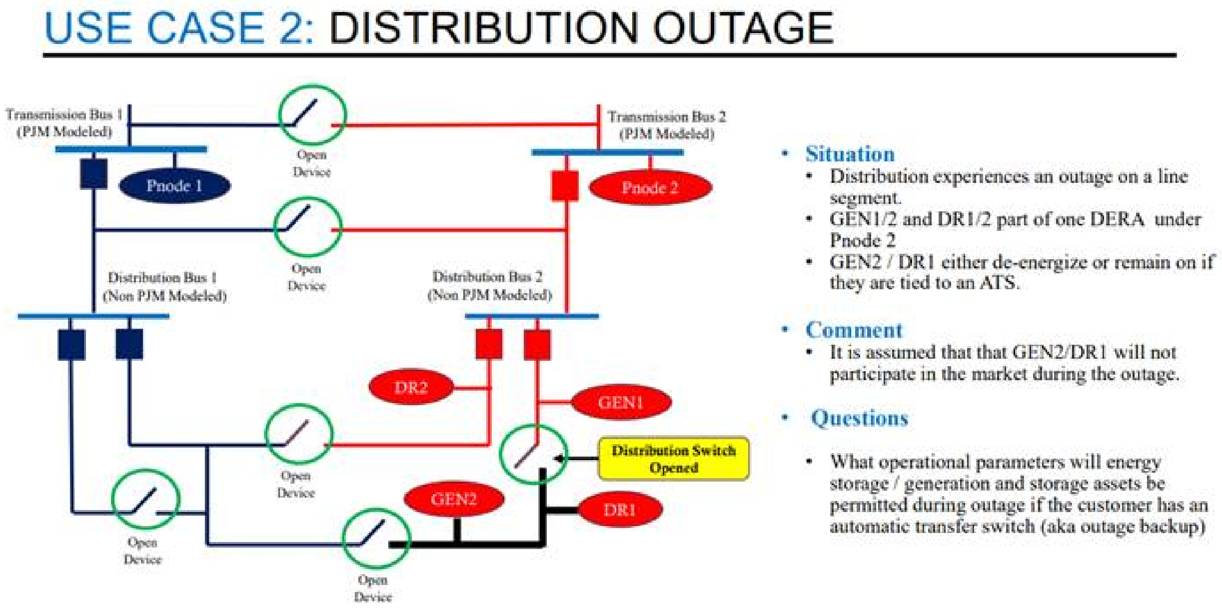


- **Market Participation:** DERA would still be able to participate at Pnode 2.

- **Operations:** DERA still able to participate in PJM. If utility has operational reliability concerns they should perform overrides, or raise any long term reliability impacts to PJM. Any long term reliability impacts would be addressed on case by case basis, but would ultimately not allow DERs to participate in wholesale market if there were safety and reliability concerns.

- **What happens if the transfer is permanent or for a long duration?** No changes as it still maps to same Pnode on PJM system

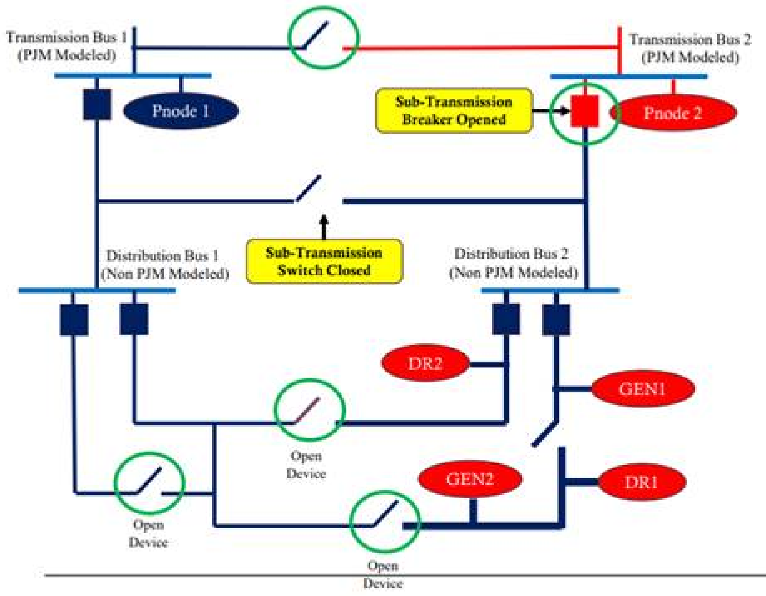
Operational Changes



- **Operations:** If there was an outage the de-energize part of a DERA we would expect parameter updates to reflect the decrease in capability for wholesale participation.
- Resource would not be able to provide back up power and be settled by PJM.

Operational Changes

USE CASE 3: SUB TRANSMISSION TRANSFER



- **Situation**
  - Sub-transmission work requires a distribution line to be moved to a different Pnode.
  - At the same time sub-transmission work has the sub-transmission re-networked.
  - GEN1/2 and DR1/2 part of one DERA under Pnode 2
- **Questions**
  - What happens to GEN1/2 and DR1/2 in terms of market participation?
  - What happens to GEN1/2 and DR1/2 operationally?
  - What happens if the transfer is permanent, or it is for a long duration?

- **Market Participation:** DERA would still be able to participate at Pnode 2, even though flows would go over Pnode 1 (assuming short term switching).

- **Operations:** DERA still able to participate in PJM. If EDC in unable to allow these resources to safely operate due to switching they should preform over-rides.

- **What happens if the transfer is permanent or for a long duration?** Modeling will be updated to reflect new “normal” distribution flows.

From FO2222

- 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.

- What is telemetry: Telemetry requirements are defining what data is being provided to PJM in real-time operations
  – After the fact meter data used for settlements discussed later in the proposal

- What DERAs have to provide telemetry to PJM?
  – Capacity – All Capacity resources, 1minute scan rate
  – Energy – All Energy only resources >= 10MW, 1 minute scan rate
  – Ancillary Service – All Regulation resources, 2/10 second scan rate; All Reserve resources, 1 minute scan rate.

- Aggregator will send telemetry values for the aggregation to PJM
  - MW telemetry values sent in all cases
  - No MVAR data required to be sent to PJM
  - Data quality flag for telemetry value
  - State of charge information needed for DERA using ESR Model
  - Meteorological (irradiance and back panel temp) data and MW for Solar >=3MW (by location/DER) at 5 min intervals
  - Transmit through Internet-based SCADA (Jetstream) or ICCP
  - Aggregators may be expected to have individual DER telemetry data available (for EDC requests and/or audit purposes)

Telemetry

Market		Telemetry	Accuracy
Capacity		1 minute data	+/- 2%
Energy Only	<10 MW	no real-time telemetry required	+/- 2%
	>=10 MW	1minute data	+/- 2%
Regulation		2/10 second data	+/- 2%
Reserves		1 minute data	+/- 2%

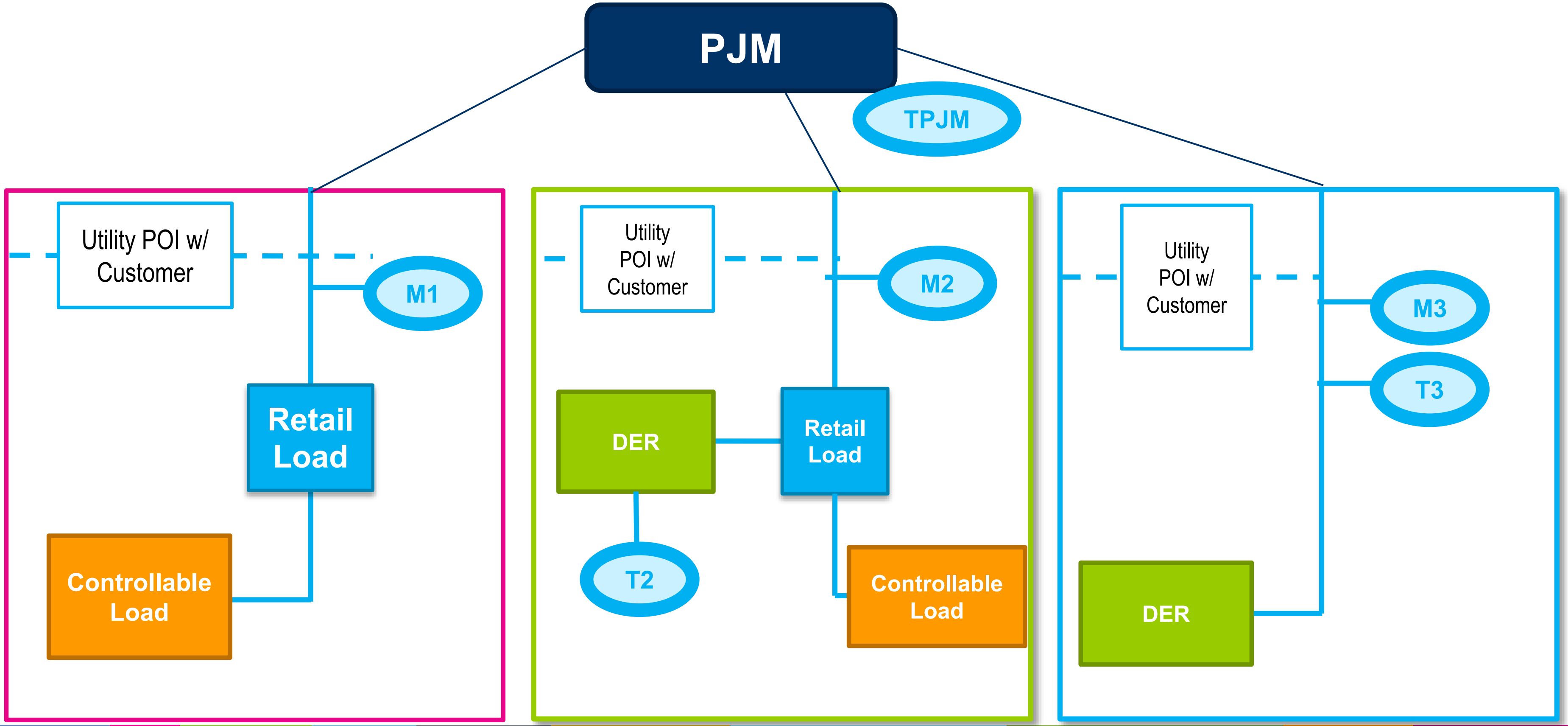
Justification:

- SE runs every minute
- SCED runs every 5 minutes
- Need to get up-to-date data into dispatch
- Tool for settlements, 5minute settlements, PAIs and reserve event performance

Telemetry

- Telemetry at aggregation level can be an accumulation of DER telemetry or an accurate representation of DER MWs
  - Demand Response resources will not need direct metering for telemetry
  - Mass Market aggregation can use sampling analysis to provide telemetry to PJM
  - Method needs to align with accuracy of settlement meters

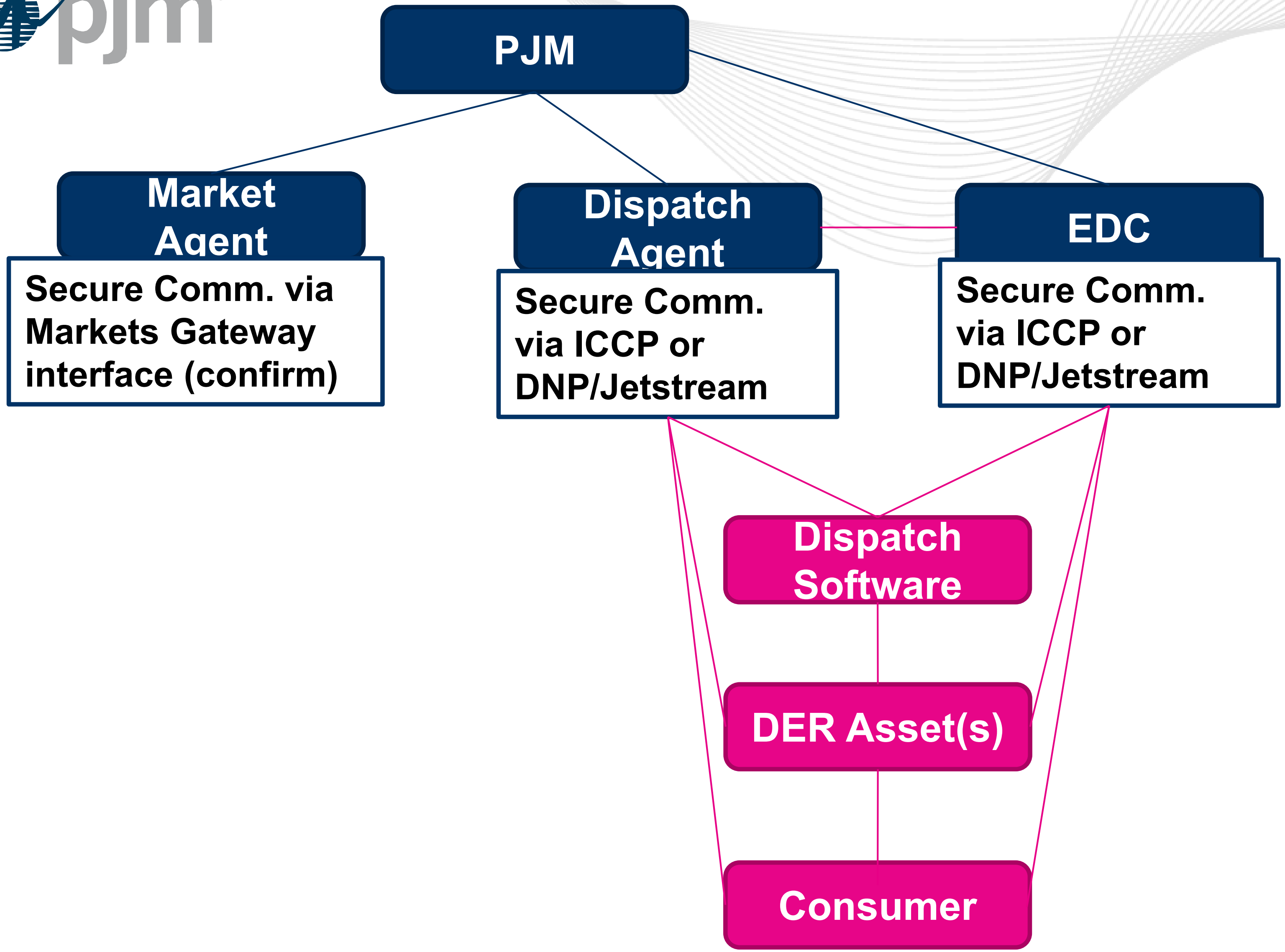
- Telemetry data back to PJM @TPJM = (DR response) + (DER + DR response) + T3
- Meter data back to PJM – M1 data and M2 data and M3 data



From FO2222

- 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*
- Cyber Security
  - PJM will implement cyber security at PJM's "first hop", aligned with CIP compliance
  - Further hops are not under PJM purview
    - Assume good security compliance further down the line governed by States and Utilities Jetstream with aggregator

Cyber Security



- Blue lines = PJM defined cyber security requirements
- Pink lines = Utility defined cyber security requirements

- Outage information will be needed for DERA CP Resources
  - Planned outages at the DERA level will need to be submitted and approved prior to PAI for excusal consideration
    - Planned outages will not be excused for Demand Response Resources (Status Quo)
  - Planned/Unplanned outages need to be submitted at the DER level for the following resources
    - All front-the-meter DERs participating in a DERA CP Resource (eFORd used in capacity calculations)
- All Energy Only DERAs with telemetry requirements (eg. >=10 MWs) will report outages to PJM

Market Design	
Market Participation Model	• New, Tariff-defined “DERA Market Participation Model” • DER Aggregations are eligible to provide all Energy, Capacity and Ancillary Services, where technically capable • Individual DERs must aggregate within the same pnode to form a DERA energy market • Broader geographic aggregation available based on Capacity and/or Ancillary Services market participation.
Type of Technology	• Homogenous and Heterogeneous
Bidding Parameters	• Commitment variables not required • ESR model available to DERAs with ESRs and Gen model to DERAs with generation respirce
Size Requirements	• Maximum size requirements on DER is 5MW • Minimum size requirement of 0.1MW for DERA

Market Design	
Capacity	• No capacity market must-offer requirement • Planned DER will be eligible to participate • DERA CP Resources will be defined within a LDA
Energy	• No commitment model • DERAs can be dispatched by PJM by providing a cost offer to PJM or can self-schedule under a no-dispatch model • Day-Ahead Energy Market must-offer requirements for DERA (based on underlying DER)
Ancillary Services	• Eligible for regulation and reserves (sync and secondary) • Will not be used for Reactive Services

- DERs can participate under existing models or the new “DERA” model in Capacity, Energy, and Ancillary Services
- Existing models available to DERs to participate in PJM markets (if they qualify) are:
  - Generator Model
  - Energy Storage Resource Model
  - Demand Response Model
  - Energy Efficiency Model
- PJM is not proposing any modifications to business rules under those models at this time or any restrictions for DERs to continue to participate under those models (status quo)

- Under the DERA model
  - DERs can participate as an aggregation (one or more DERs) in PJM Markets in a DER Aggregation
  - DERAs can be homogenous (include one resource/technology type) or heterogeneous (include multiple resource/technology type)
  - DERs at multiple locations (on distribution) can still be considered homogenous if they are made up of the same resource/technology type

Managing Aggregations

- DER Aggregations (DERAs) will participate in Energy and Ancillary Services
  - Will meet the nodal locational requirements
  - DERAs can further aggregate for regulation performance
  - Ancillary Service Only aggregations can be aggregated more broadly.
- DERA Capacity Resource will participate in the Capacity Market
  - One or more DER and/or DERAs can make up a DERA CP Resource
  - Location requirements based on zonal/sub-zonal LDA requirements in RPM

Market Participation Model

Requirements	Capacity	Energy	Ancillary Services Only
Locational Requirement	Aggregate multiple DERAs up to zonal/ sub-zonal LDA	Aggregate DER up to primary location (nodal)	Aggregate DER up to EDC / TO zone level
Size – DERA min and max	100kw min, no max	100kw min, no max	100kw min, 5MW max

Managing Aggregations

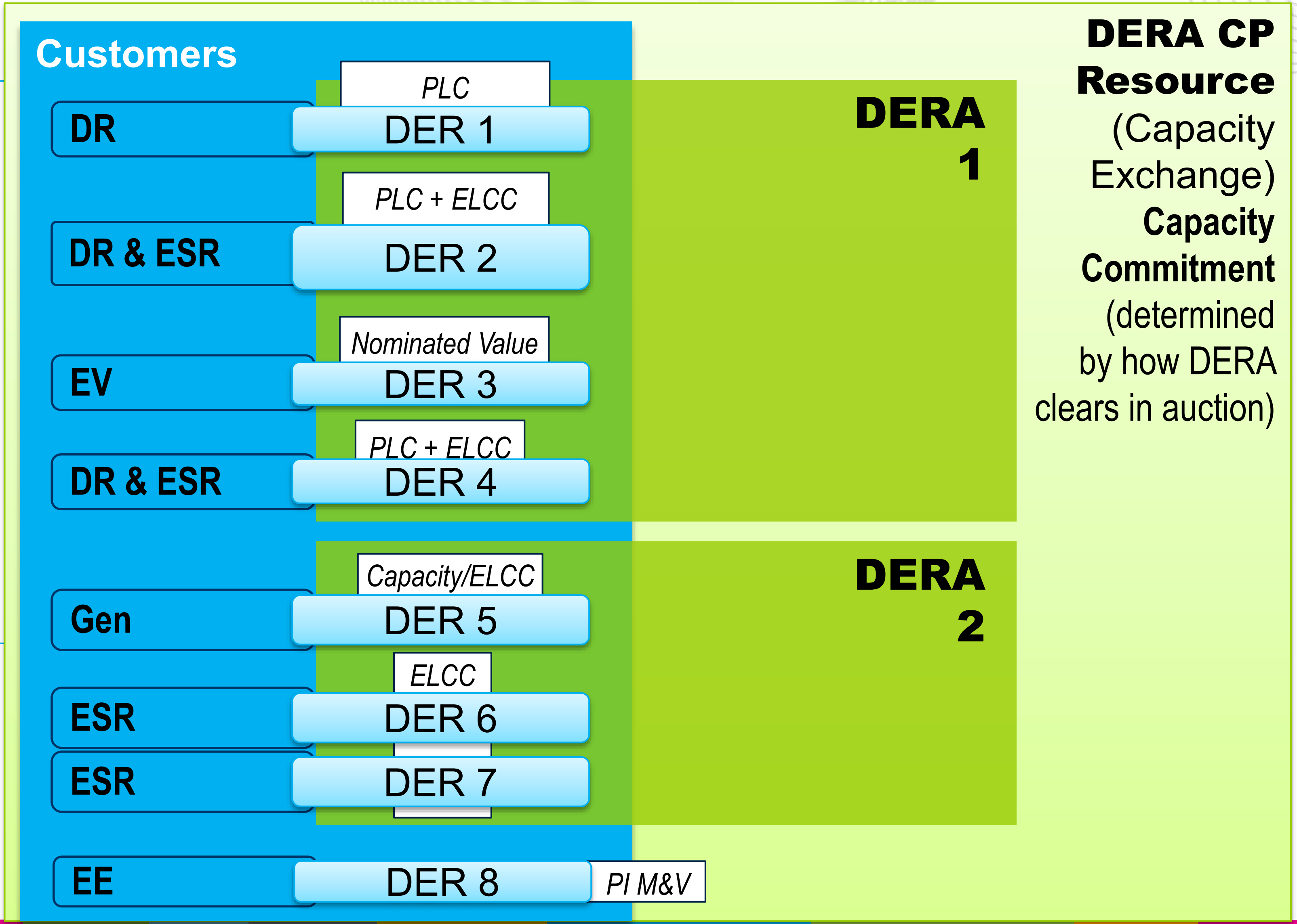
DER	(Utility Review) Primary transmission location	Aggregations for dispatch (locational reqts) –Energy & Ancillary	Aggregations for Capacity (DERA CP Resource)*	Aggregations for Regulation Performance^
DER1	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER2	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER3	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER4	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER5	Node B	DERA 2	DERA CP 1	DERA 1, 2 & 3
DER6	Node C	DERA 3	DERA CP 1	DERA 1, 2 & 3

- *Meets LDA requirements in Capacity
- ^Meets performance group requirements for regulation

Market Participation Model

Registration/ Utility Review

- Define DERs in DERAs and capture necessary information
- DER aggregator, Location, Capacity Value, MOPR



Energy/ A/S Resource
- Market Resource ID
- Locational requirement defined
- Min = 100 kW
- Max = no max requirements

CP Resource
- Aggregation of many DERs across LDA
- Min = 100 kW
- Max = No max requirements
- Energy Resource cannot be split across DERA CP Resources

Capacity Value

Capacity

- Homogenous or Heterogeneous DERA CP Resource assigned to a zone/sub-zonal LDA based on the location of underlying DERs

- DERA CP Resource may voluntarily offer into the Capacity Market and is not subject to RPM Must Offer Requirement
  - Capacity value to offer based on capacity values calculated at the DER level and aggregated to the DERA CP Resource level
  - Offer price may be subject to MOPR and MSOC based on the underlying DERs
    - Only FTM DERs subject to MOPR and MSOC

Capacity Capability follows resource type

DER	Capacity Capability	Testing
FTM Gen	(Status Quo) ICAP*eFORd	• Annual summer/winter capacity testing • 1hour test
FTM ESR	(Status Quo) ELCC	
FTM Solar	(Status Quo) ELCC	not subject to summer and winter capability testing (M18)
Demand Response	(Status Quo) Nominated Value based on PLC	Annual DR testing
Continuous DER (Behind retail load DER)	capacity value based on PLC + capacity value of injection MW	Annual DR testing + verification of generator capacity and injection
EE	(Status Quo) Nominated Value based on Offer Plan	M&V Audit

- Capacity testing will be performed at the DERA/DER level
  - Aligned with the capacity commitment allocation at the DERA/DER level
  - If testing failure/penalty occurs at DERA/DER level, the shortfalls of the DERA/DER will be aggregated up to the DERA Capacity Resource level.

Market Participation Model

- Capacity value is assigned at the DER level and added to determine the DERA Capacity value; testing is performed and verified at the DER level
- 1 or more DERA may aggregate to a DERA CP resource, DERA CP Resource capacity value that can be offered into RPM is the summation of the underlying DERA capacity values
- Committed Capacity is at the DERA CP Resource
- May have more registered capacity value than is needed to satisfy the DERA CP Resource commitment; Committed capacity can be less than available capacity

Capacity

- Non-Performance Assessment applies to a committed DERA CP Resource
  - Subject to Non-Performance Charge if underperform and subject to Bonus Performance Credit if over-perform
  - Actual Performance will be calculated at DERA level (energy market resource level)
    - Exception for Energy Efficiency
  - Excusals for outages (assuming an approved outage during PAI)
  - No dispatch excusal if dispatched or overrides by utility for reliability
  - Netting of performance will be available for DERAs within the DERA CP Resource
    - No netting of performance across DERA CP Resources in a market seller account

Capacity Participation

- **Planned DERA CP Resource** will be able to participate in the Capacity Auction under certain circumstances.
  - Planned DERA will be able to participate by submitting a plan to PJM, with an attestation on deliverability, to be able to offer into a Capacity auction prior to the DER being operational and registering with PJM
  - Single plan submitted for a Planned DERA CP Resource. The plan would address:
    - Technology type, number of customers and zone/subzone LDA needs to be identified. Site-specific information needed in a zone of concern.
  - Planned DER will offer in as DERA CP Resource with minimize size requirements of 0.1MW

Capacity Participation

- **Emergency DER** will be ineligible to participate in Capacity under a DERA.
  – DER that is Pre-Emergency/Emergency load response will not be able to participate in a DERA CP Resource.
  – Pre-Emergency/Emergency load response will still be able to participate in Capacity Demand Resource
- Must Offer Requirement in DA Energy Market is being extended to DERA CP Resources
  – Need visibility into the planned operation of these resources under high penetration levels.

Energy Market Model

Aggregation	Energy Market Model	Energy Must Offer	Cost Offer*
Homogenous – front of meter DER (gen, solar, battery)	Generation Model, ESR Model, or DERA Model	Gen = ICAP Solar/ESR = MW offer may vary	Follow Manual 15 for non zero cost offers
Homogenous – DR	DERA Model	MW offer may vary	Cost Offers = $0
Homogenous-Continuous DER^	DERA Model	MW offer may vary	Cost Offers = $0
Homogenous – EE	N/A	N/A	N/A
Heterogeneous	DERA Model	MW offer may vary, generator resources must offer ICAP	Cost Offers = $0

^Continuous DER = behind retail load with injection

* Opportunity to develop M15 methodology for cost based offers at the Cost Development Subcommittee.

Energy Model Comparisons

Model	Gen	ESR	Econ DR	DERA
Cost Offers	Yes	Yes	No	Yes
Self-Schedule	Yes	Yes, can schedule at 0MW	Yes	Yes, can schedule at 0MW
Must Offer	Yes	Yes	No	Yes
Dispatchable	Yes	Yes	Yes	Yes
Wholesale Charging Energy	No	Yes	No	No

Bidding Parameters available in DERA model

- For dispatchable resources in DERA model the following parameters will be available
  - Offer curve, MW/price pairs
  - Economic Minimum/Maximum
  - Emergency Minimum/Maximum
  - Ramp Rate

Energy

- Two options for Energy Dispatch available under DERA Energy Market Model
  - Option 1: DERA will participate in Energy under a no-commitment, no-dispatch model.
  - Option 2: DERA will participate in Energy under a no-commitment model, PJM dispatch available
- No commitment model allows DERA resources to self-schedule into PJM energy market, and may self-schedule at 0MW and a dispatchable range for economic dispatch

Energy

- no-commitment, no-dispatch model
  - DERAs will be expected to self-schedule energy into the DA and RT energy markets based on their forecasted availability.
  - DERAs will be required to submit $0 cost based offers.
  - DERAs will not be eligible for LOC or make whole.
- no-commitment, PJM dispatch model
  - Homogeneous DER aggregations will follow Manual 15 language and construct FCP for non-zero cost based offers.
  - Heterogeneous DER aggregations will have zero cost based offers. There is an opportunity to develop cost based offers in the future at the Cost Development Subcommittee.
  - DERAs will be eligible for LOC or make whole if manually dispatched.

Ancillary Services

- DER aggregations (DERA) will be allowed to participate in the Regulation and Reserves Ancillary Service markets
- DERAs will be eligible to offer resources into Black Start RFPs for consideration on Black Start Service. However, **PJM believes it would be unlikely DERAs would qualify for Black Start and may pose concerns for distribution reliability.** DERAs would be evaluated on a case-by-case basis based on RFP response
- DERAs will not be considered for Reactive Support or required to provide VAR data to PJM

Ancillary Services - Reserves

- DERAs will follow the same business rules as detailed in Manual 11 Section 4 for reserves.
  - DERAs are ineligible to provide non-synchronized reserves
    - DERAs will be self-committing into PJM's Market and therefore will be considered synchronized when scheduled. Will be considered offline/unavailable when not self-committed
  - DERAs will need to be contained within a predefined reserve zone or subzone
    - Single node locational model should address this requirement
  - Under the new reserve pricing model (May 2022), DERAs will be eligible for secondary reserves participation, given they have a valid energy offer.
  - DERAs will have the opportunity to participate in Reserves as a "Reserves Only" resource, or as ancillary participation to energy.

Ancillary Services - Reserves

- DERAs, by default, will not be considered for reserves, based on underlying technology, but may request an exception to participate.
  - Follow proposed process for Reserve Pricing eligibility that was presented at June 30, 2020 MIC Special Session – Reserve Price Formation Order
    - https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200630-special/20200630-item-03a-resource-eligibility-for-reserves-proposal.ashx

Ancillary Services - Regulation

- DERAs will follow the same business rules as detailed in Manual 11 Section 3 and testing requirements as detailed in Manual 12 Section 4.5 for regulation.
  - DERAs are eligible to provide regulation service
  - DERAs can participate in Regulation as a stand-alone aggregation, or utilize performance groups to aggregate performance over multiple aggregation
  - DERAs will have the opportunity to participate in Regulation as a “Regulation Only” resource, or as ancillary participation to energy.

Ancillary Services - Regulation

- Performance Group requirements in Manual 12 Section 4.5.7
- Use of Performance Groups in the Performance Score Resources may elect to use a performance group for performance score evaluation. Performance groups can only be created for resources that satisfy one of the following criteria:
  - Resources not eligible for LOC and total to less than or equal to 10 MW across Transmission Owner boundaries.
  - A performance group can be any number of resources not eligible for LOC inside a Transmission Owner's boundary.
  - Resources within a fleet with equivalent applicable offers and point of interconnection.

Min/Max Size Requirements

From Order 2222

- *Establish a minimum size requirement for DER aggregations that does not exceed 100 kW (171)*
- *Direct each RTO to propose a maximum capacity requirement for individual distributed energy resources participating in its markets through a distributed energy resource aggregation or, alternatively, to explain why such a requirement is not necessary (179)*
- *Does not adopt a maximum size requirement for distributed energy resource aggregations that span multiple pricing nodes. (174)*

Min/Max Size Requirements

Size Requirement	Minimum	Maximum
DER Resource	• No minimum	• lesser of 5MW or EDC requirements for interconnection
DER Aggregation	• 0.1MW minimum	• No maximum for Energy and Capacity • 5MW maximum for ancillary service DERA with broader aggregation

Sizing Requirements for DERs (individual resources)

- No minimum requirements will be defined
- Maximum requirements will be the lesser of 5MW or EDC requirements for interconnection
  - Needed to ensure larger resources are studied by PJM for transmission impacts and additional visibility into resource operations are provided for Operations.
  - >5MW (nameplate) resources participation in PJM's market on its own, under the generation model, or Demand Response model should not provide a burden to resources
    - Many resources <=5MW participating in PJM today

Settlements	
Metering Configuration & Requirements	• Data submissions for settlements will follow existing PJM PowerMeter and InSchedule requirements
Settlement Requirements	• Uphold Order 745 for DR Settlements
Double Counting Services	• Double counting will not be permitted participating in PJM Markets • Determination of double counting due to retail activity will be determined by the EDC
Use Case Development	• List of use cases to test proposal requirements

- Existing Metering Requirements located in Manual 14D
  - Section 4.2.2: Metering Plan
  - Section 4.2.3: Metering for Individual Generators
    - *"…a Generation Owner can negotiate data transmission to and from PJM through the local utility or transmission facilities owner. This allows the Generation Owner the flexibility to use already proven and acceptable methods of data transfer to* ***minimize initial startup costs and procedures, while meeting all of the current requirements*** *for providing data to PJM."*
    - *"…can be supplemented with the use of the Internet-based PJM Tools such as inSchedule and Data Viewer, further expanding the data transfer capabilities between the customer and PJM without a direct connection to PJM."*

- Real-time (RT) revenue data is required to be submitted into PowerMeter either on a 5 minute or hourly basis in accordance with Manual 28, sections 1A and 3
  - Current PowerMeter and InSchedule deadlines – PowerMeter is next business day
- MW data true up
  - Generator RT MWh use the One-Month-Lag Meter Correction process via PowerMeter
  - LSE RT load MWh use the Two-Month-Lag Load Reconciliation process via InSchedule (needed because generator metering updated)

- DERAs will be settled at the aggregation level in PJM Markets; however meter data will need to be submitted at the individual DER level

- This will allow PJM the ability to properly settle MWh for different types of DERs and accurate wholesale/retail settlements need to occur

Settlements – DR Participation

- PJM will settle Demand Response resources participating in a DERA (homogeneous or heterogeneous) with Order 745 requirements.
- Demand Response resources that wish to participate in a DERA will have the following additional requirements
  - Submit metered data through DR Hub following the PowerMeter deadline (1 business day after the Operating Day)
  - Mapped at a pricing node (instead of the zonal residual aggregate)

- DERAs which clear day-ahead will be settled as day-ahead spot market at the LMP which they cleared

- If any demand response resources are in a DERA, the actual real-time load reduction will be used to carve out the DR activity
  - For any demand response MWs, the day-ahead load of the associated LSE will be adjusted
  - Demand Response MWs will be settled following demand response business rules.

- Whenever a Demand Response resource clears day-ahead, PJM applies a negative load bid in day-ahead to the LSE associated with the registration.

- This negative load bid will be referred to as the negative dec bid throughout this presentation.

- DERAs which clear day-ahead will be settled for any deviations from day-ahead commitments in the balancing spot market
  - When dispatched in real-time, the day-ahead commitment will be zero
- Any demand response in a DERA will have reductions settled as real-time load response

- With DERAs being modeled as no-commitment units, DERAs that clear Day-ahead or are Dispatched by PJM in real-time will not be eligible to receive Operating Reserve Make-whole Credits, unless they are manually dispatched by PJM

- DERA resources can receive Operating Reserve Deviation Charges.

Settlements Example

Generator LMP Charge Summary

Generator LMP Charge Summary																		150	2.5	1.25	
4000.01	4000.02	4000.05	...	4001	4001	3000.8	4000.19	4000.2	3000.32	3000.01	1200.11	3000.06	1210.18	3000.15	1220.18	3000.33	3000.91	1205.11	1215.2	1225.2	4000.07
Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	PNODE Name	PNODE ID	EPT Hour Ending	DA Scheduled MWh	DA PJM Energy Price ($/MWh)	DA Spot Market Energy Charge ($)	PNODE DA Congestion Price ($/MWh)	DA Transmission Congestion Charge ($)	PNODE DA Loss Price ($/MWh)	DA Transmission Loss Charge ($)	RT Generation (MWh)*	Bal Generation (MWh)	Bal Spot Market Energy Charge ($)	Bal Transmission Congestion Charge ($)	Bal Transmission Loss Charge ($)
...	...	07/01/2021 10	...	...	...	1	DERA PNODE 1	...	10	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 11	...	...	...	1	DERA PNODE 1	...	11	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 12	...	...	...	1	DERA PNODE 1	...	12	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 13	...	...	...	1	DERA PNODE 1	...	13	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 14	...	...	...	1	DERA PNODE 1	...	14	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 15	...	...	...	1	DERA PNODE 1	...	15	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0
...	...	07/01/2021 16	...	...	...	1	DERA PNODE 1	...	16	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0
...	...	07/01/2021 17	...	...	...	1	DERA PNODE 1	...	17	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0
...	...	07/01/2021 18	...	...	...	1	DERA PNODE 1	...	18	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0

Settlements Example DR

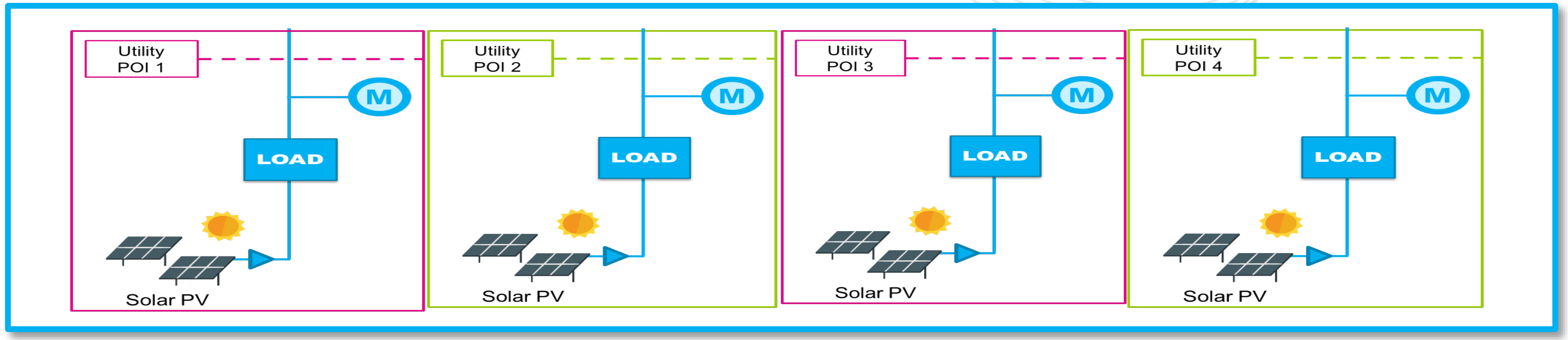
Load Response Summary

Customer ID	Customer Code	Billing Month	EPT Hour Ending	GMT Hour Ending	Registration ID	EDC Account Number	End Use Customer	Zone	EPT Hour Ending	DA Load Response MWh	DA LMP ($/MWh)	DA Retail Rate Used ($/MWh)	DA Load Response Credit ($)	DA Load Response Charge ($)	CBL (MWh)	Metered Load (MWh)	Load Response Loss Factor	EDC Loss De-ration Factor	RT Load Response MWh	RT LMP ($/MWh)	RT Retail Rate Used ($/MWh)	RT Load Response Credit ($)	RT Load Response Charge ($)
4000.01	4000.02	4000.03	4000.05	4000.1	4000.9	4000.94	4000.95	4000.32	3000.32	3001.14	3000.24	1240.11	2240.01	1240.01	1241.11	1241.12	1241.13	3000.83	3001.15	3000.25	1241.14	2241.01	1241.01
123456	ABCDEF	7/1/2021 04	07/01/2021 10	07/01/2021 14	R1234	12341	DERA DR Reg	PE	10	3	100	0	300	0	5	3	1.01	0.01	1.9998	150	0	-150.03	0
123456	ABCDEF	7/1/2021 04	07/01/2021 11	07/01/2021 15	R1234	12341	DERA DR Reg	PE	11	3	100	0	300	0	5	2	1.01	0.01	2.9997	150	0	-0.045	0
123456	ABCDEF	7/1/2021 04	07/01/2021 12	07/01/2021 16	R1234	12341	DERA DR Reg	PE	12	3	100	0	300	0	5	4	1.01	0.01	0.9999	150	0	-300.015	0
123456	ABCDEF	7/1/2021 04	07/01/2021 13	07/01/2021 17	R1234	12341	DERA DR Reg	PE	13	3	100	0	300	0	5	3	1.01	0.01	1.9998	150	0	-150.03	0
123456	ABCDEF	7/1/2021 04	07/01/2021 14	07/01/2021 18	R1234	12341	DERA DR Reg	PE	14	3	100	0	300	0	5	2	1.01	0.01	2.9997	150	0	-0.045	0
123456	ABCDEF	7/1/2021 04	07/01/2021 15	07/01/2021 19	R1234	12341	DERA DR Reg	PE	15	2	100	0	200	0	5	2	1.01	0.01	2.9997	150	0	149.955	0
123456	ABCDEF	7/1/2021 04	07/01/2021 16	07/01/2021 20	R1234	12341	DERA DR Reg	PE	16	2	100	0	200	0	5	4	1.01	0.01	0.9999	150	0	-150.015	0
123456	ABCDEF	7/1/2021 04	07/01/2021 17	07/01/2021 21	R1234	12341	DERA DR Reg	PE	17	2	100	0	200	0	5	5	1.01	0.01	0	150	0	-300	0
123456	ABCDEF	7/1/2021 04	07/01/2021 18	07/01/2021 22	R1234	12341	DERA DR Reg	PE	18	2	100	0	200	0	5	5	1.01	0.01	0	150	0	-300	0

Double Counting

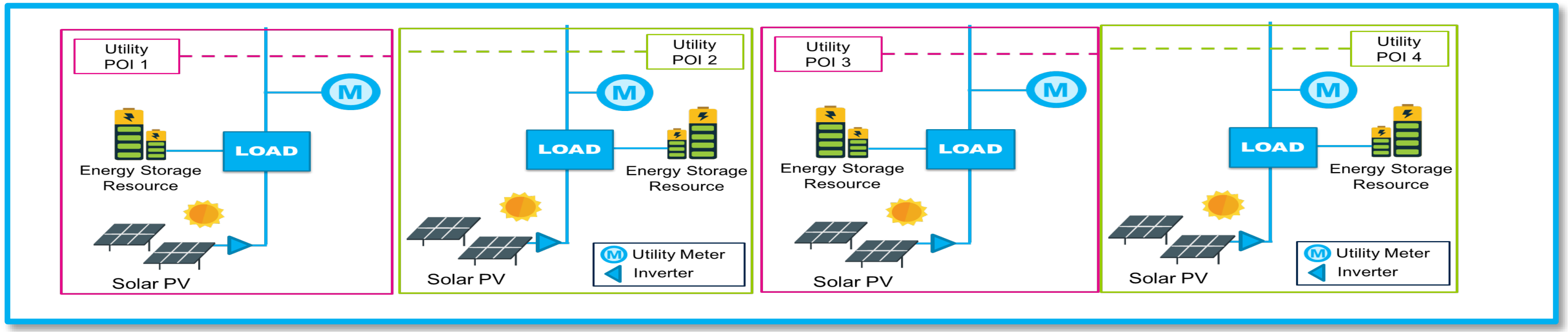
- **Double Counting Services:** limit the participation of resources in RTO/ISO markets through a distributed energy resource aggregation (DERA) that are receiving compensation for the same services as part of another program.
  - Double Counting not permitted in PJM markets; resources cannot be compensation for the same MWs/services in retail and wholesale

- NEM Use Case 1: Solar resource(s) participating in NEM programs



Determination needed by EDC if Solar resource can participate in PJM Markets without double counting

- NEM Use Case 2: Solar resource(s) participating in NEM programs with co-located ESR



Determination of solar participation (use case 1) and if ESR can participate in PJM Markets and necessary metering

- **Retail Net-Energy Metering (NEM)** : DER Resources modeled at a location with a NEM rate and wanted to participate in wholesale markets through a DERA.
  - Participation in wholesale market will need to be approved by EDC after evaluation of resource(s) participation in NEM program and the associated revenue for that participation
    - The will be implemented in the Utility Review process, and will be on a utility-by-utility bases to capture different utility NEM requirements
    - Example: an “all in” NEM rate that already compensates for capacity and ancillary services will not be able to participate in PJM Markets without double counting. NEM rates that are “energy only” may allow resource(s) to participate in PJM Markets.

Double Counting

- **Wholesale / Retail Market Coordination**: An example of this scenario would be Flagging for normal DR activity while Peak-shaving for Capacity. Any such activity would need to be monitored and flagged.
  - For situations such as the example above, resources would be scheduled for retail, and they would not be paid for wholesale.

- **Wholesale service (such as front of the meter generation) and distribution service being run at the same time**: In this scenario, a resource is dispatched by PJM for distribution level services, therefore, they are self-scheduled for energy in the PJM Market. An example of such would be a battery that is running on-peak.
  - If the resource is dispatched, it must reflect this in their wholesale market offer.

Purpose of Use Cases

- Stress test the DERA model
- Build understanding by filling in details
- Cohesive examples to use throughout compliance process
- Highlight technology-specific needs
- Ability to iterate and introduce alternatives

- Characteristics from **September DIRS**

Composition	Whether diversity exists within the DERA; can be “of resource type” or “of technology type” and at site level, or at DERA level Homogenous: only one type is present; Heterogeneous: multiple types are present
Configuration	Relation of the DER physical elements to retail load Front of the meter: not co-located with retail load Behind the meter: co-located with retail load
Resource Type	Distinguishes the nature of a DERA resource and its contribution to the system *DGR; DR; DRwDI*
Technology Types	Mechanism or activity by which power is generated or load reduced within DERA DGR: Solar, wind, ESR, etc. DR: Controllable retail load, DGR co-located with retail load, etc.
Market Participation	Market services the DERA is technically capable of providing Capacity; Energy; Ancillary Services
Sites	Number of geographically distinct sites registered. One or more sites comprise a DERA.

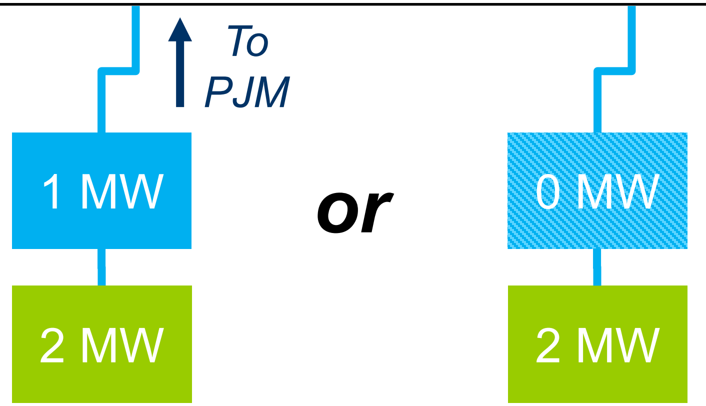
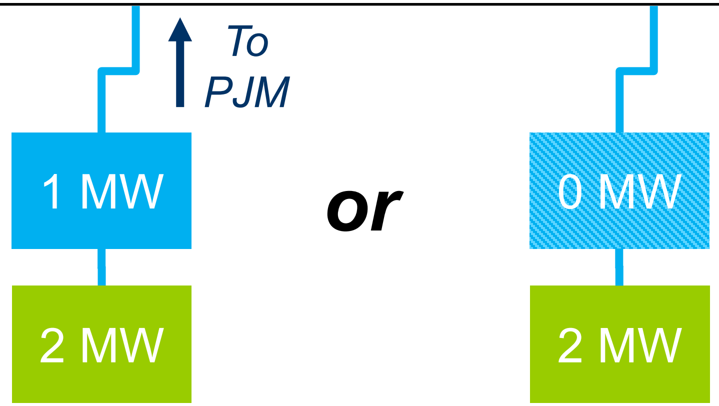
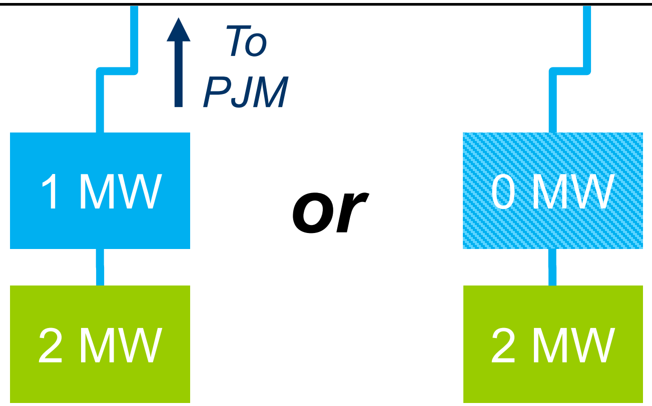
Resource Type is a **market distinction**, not a UC characteristic

Resource Type as Market Distinction

- BTM Generator with max output greater than potential max retail load

Example:

Active Load Reduction | Generator | Retail Load | Distribution System

Load Reduction *with Injection* (DRwDI)	… choosing to participate as Load Reduction (DR)	…choosing to participate as Injection *only* (BTMG Injection)
		
1 MW reduction, 1 MW injection **or** 1 MW reduction **+** 2 MW injection where retail load = 0 *(Max 2 MW injection)*	1 MW reduction **or** 0 MW reduction where otherwise retail load = 0 (*Max 2 MW injection*)	1 MW injection **or** 2 MW injection where retail load = 0 *(Max 2 MW injection)*

Updates to Use Case Characteristics

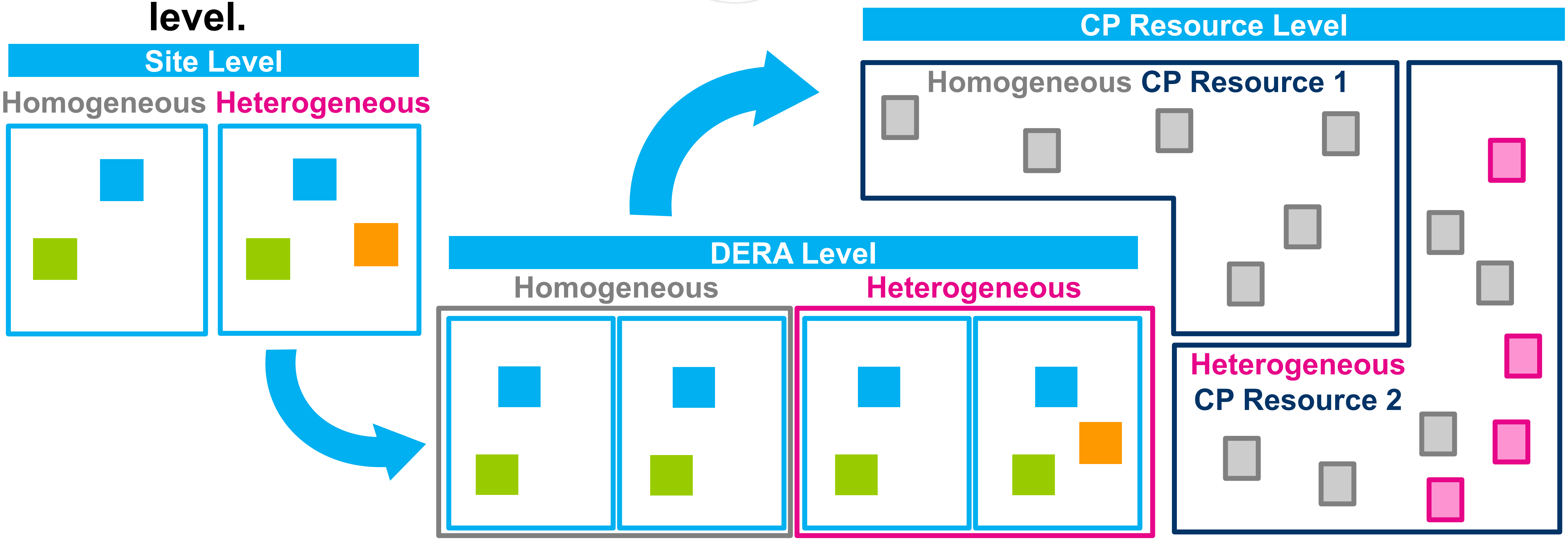
Composition	Whether diversity exists within the DERA; can be “of resource type” or “of technology type” and at site level, or at DERA level Homogenous: only one type is present Heterogeneous: multiple types are present
Configuration	Relation of the DER physical elements to retail load Front of the meter: not co-located with retail load; Behind the meter: co-located
Technology Types	Mechanism or activity by which power is generated or load reduced within DERA Solar, wind, ESR, diesel, controllable retail load, etc.
Sites	Number of geographically distinct sites registered. One or more sites comprise a DERA.

Use Cases: Outline

	Composition	Configuration	Sites	Use Case Goal
1	Homogeneous	Front of the meter	One	• Demonstrate size requirements and their implications.
2	Heterogeneous	Front of the meter	Multiple	• Demonstrate information exchange on an aggregate basis. • Walkthrough utility review with multiple distribution feeders.
3	Homogeneous	Behind the meter	One	• Demonstrate participation for sites co-located with retail load. • Illustrate rules where aggregates contain both potential for transmission injection and load reduction.
4	Heterogeneous	Behind the meter	One	• Demonstrate participation for sites co-located with retail load. • Illustrate rules where aggregates contain both potential for transmission injection and load reduction. • Highlight rules for multiple technology types where necessary.
5	Homogeneous	Behind the meter	Multiple	• Illustrate an aggregation of **many customer sites with BTM generation** wanting to participate in one or multiple markets.
6	Heterogeneous	Behind the meter	Multiple	• Illustrate an aggregation of **many customer sites, each with mixed technology types**, wanting to participate in one or multiple markets.
7	Homogeneous	Behind the meter	Multiple	• Illustrate an aggregation of **many distinct customer sites with load reduction** wanting to participate in one or multiple markets.

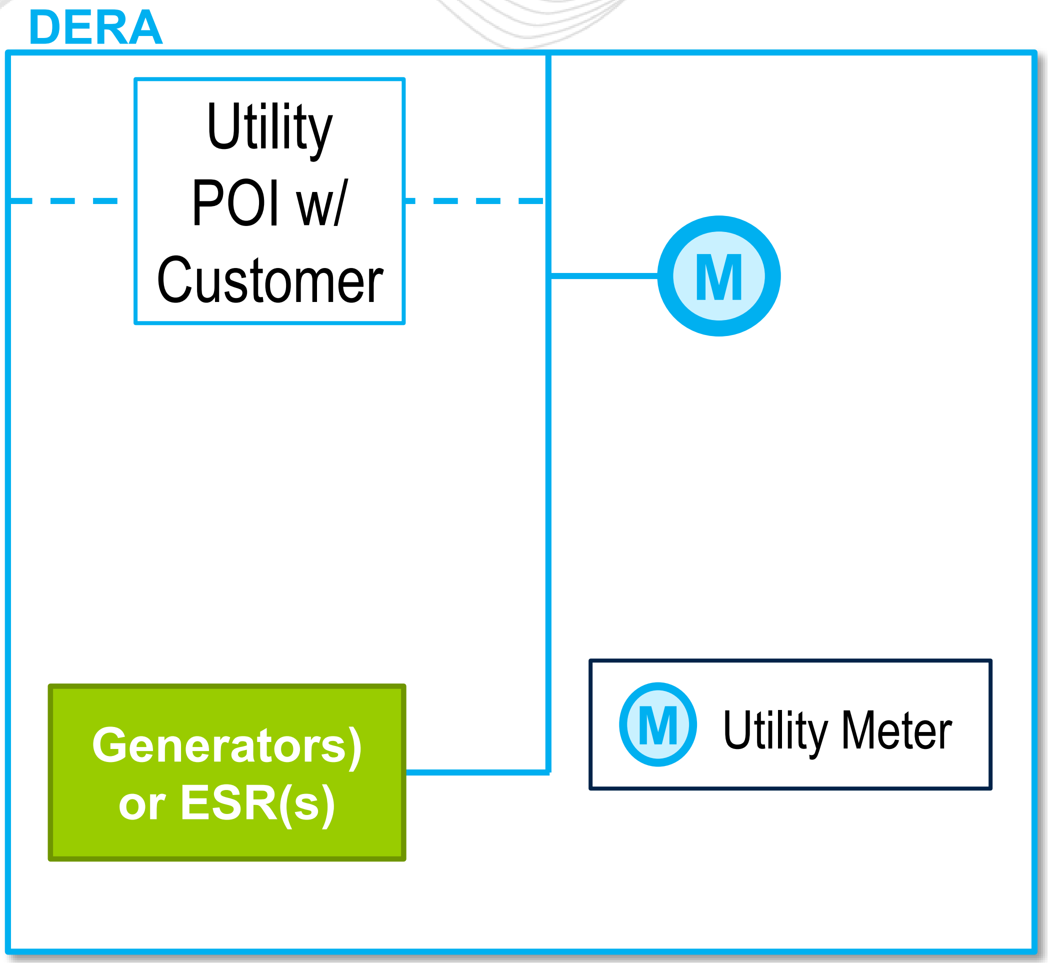
*** Errata: Use Case 5 was labeled as Heterogeneous, but presented as Homogeneous in Sept DIRS—corrected.*

- Where diversity exists within the DERA, it can be "of resource type" or "of technology type" and **at site level, or at DERA level, or at CP resource level.**



Use Case 1

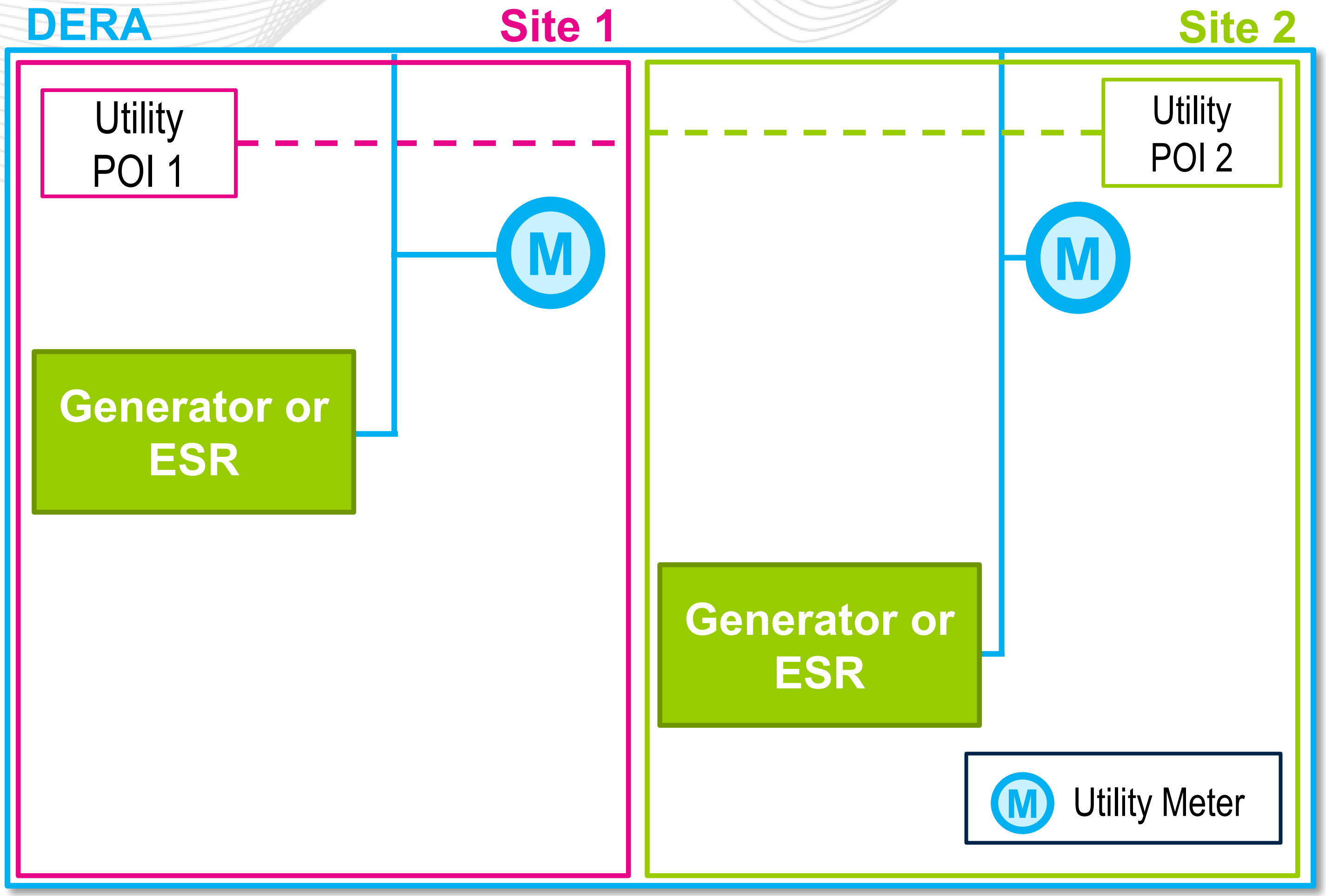
- A single distributed generator or ESR (single fuel type) at a…
- Single geographic site
- Participating as a single DERA
- Not co-located with retail load



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Use Case 2

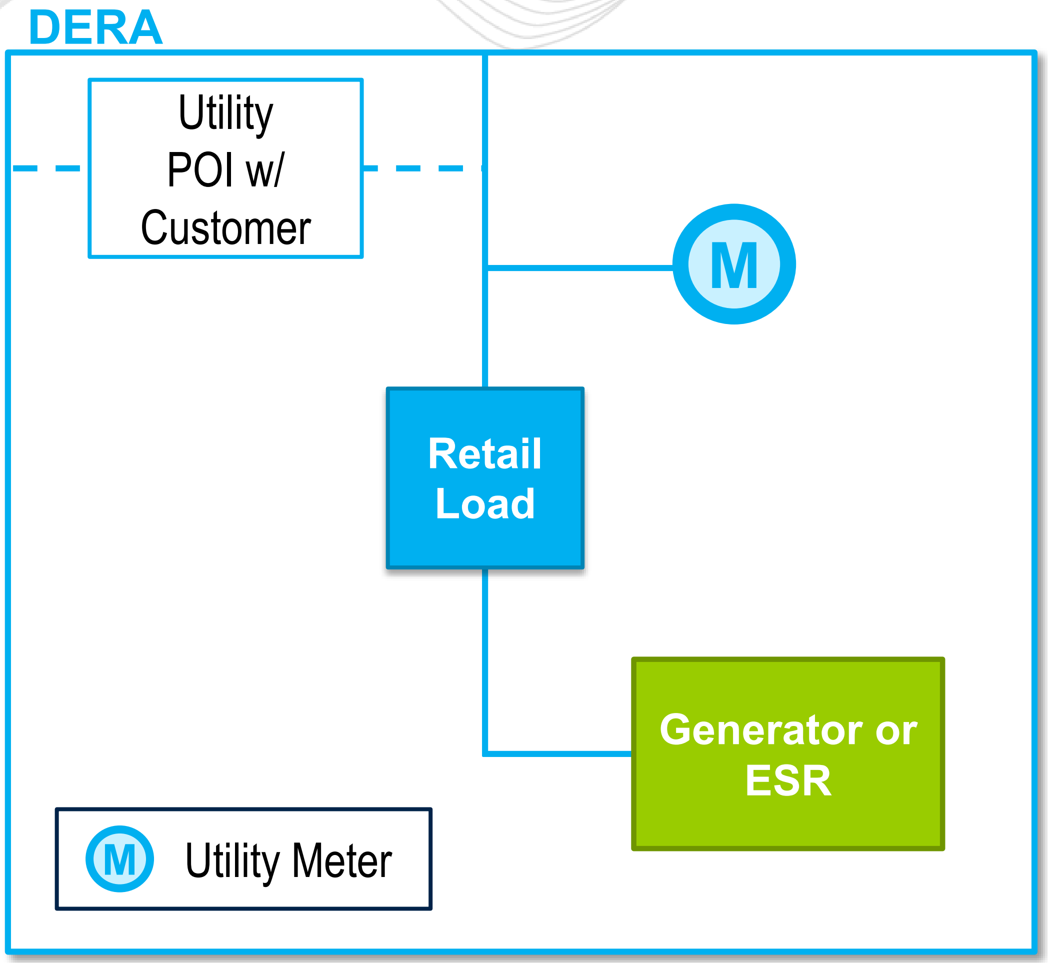
- A single distributed generator or ESR (single fuel type) at…
- Multiple geographically distinct sites
- No sites in DERA co-located with retail load



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Use Case 3

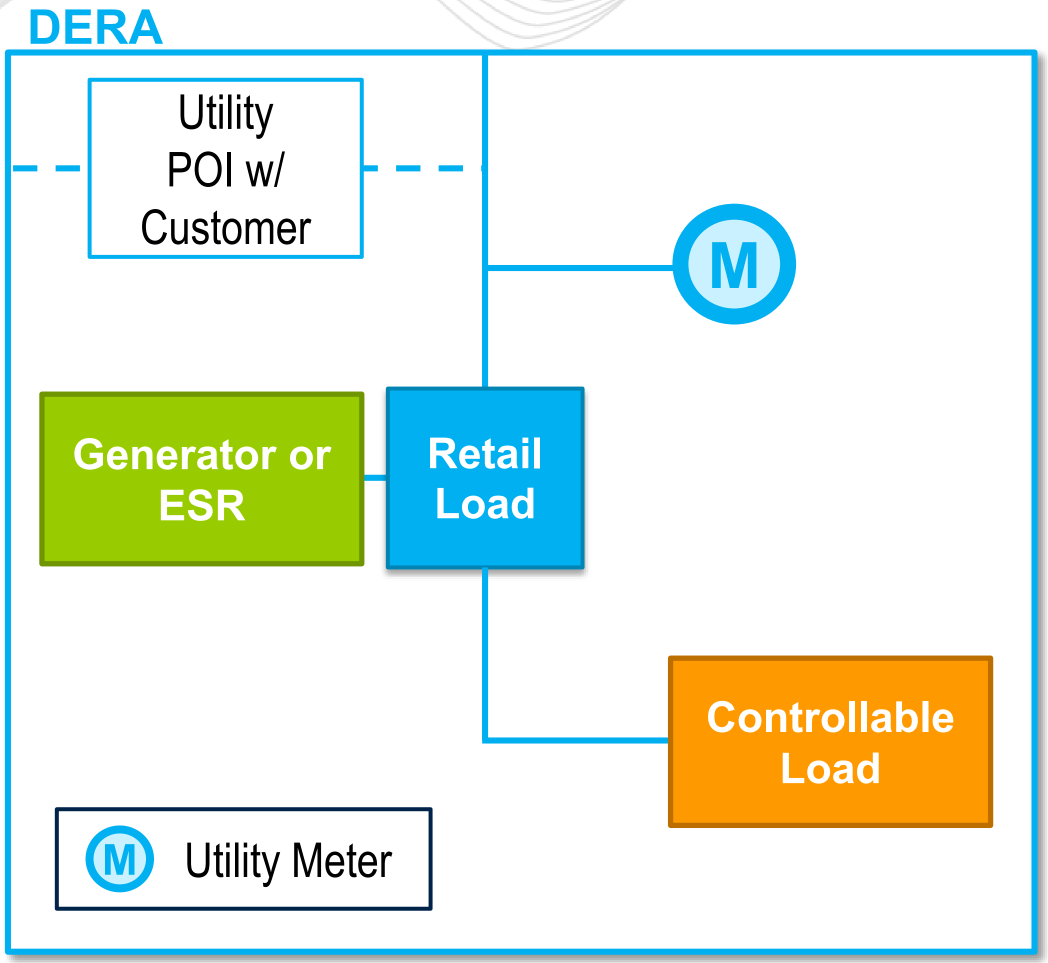
- A single distributed generator or ESR (single fuel type) at a…
- Single geographic site participating as a single DERA
- Site co-located with retail load
- Site may inject
- Can elect market participation as DRwDI **or** net injection BTMG **or** DR



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Use Case 4

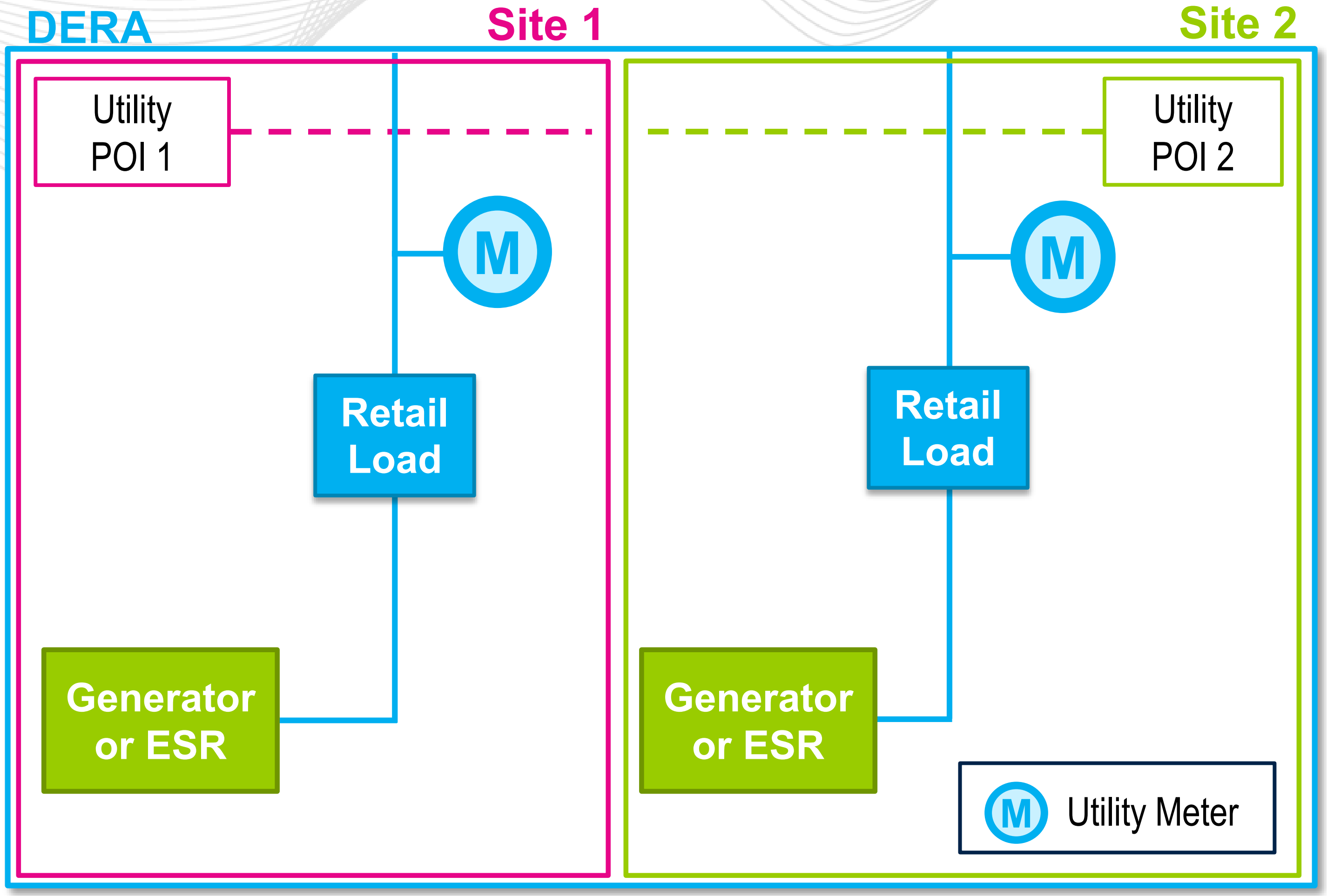
- Both a distributed generator/ESR and an active load reduction located at a…
- Single geographic site participating as a single DERA
- Site co-located with retail load
- Can elect market participation as DRwDI **or** net injection BTMG **or** DR



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Use Case 5

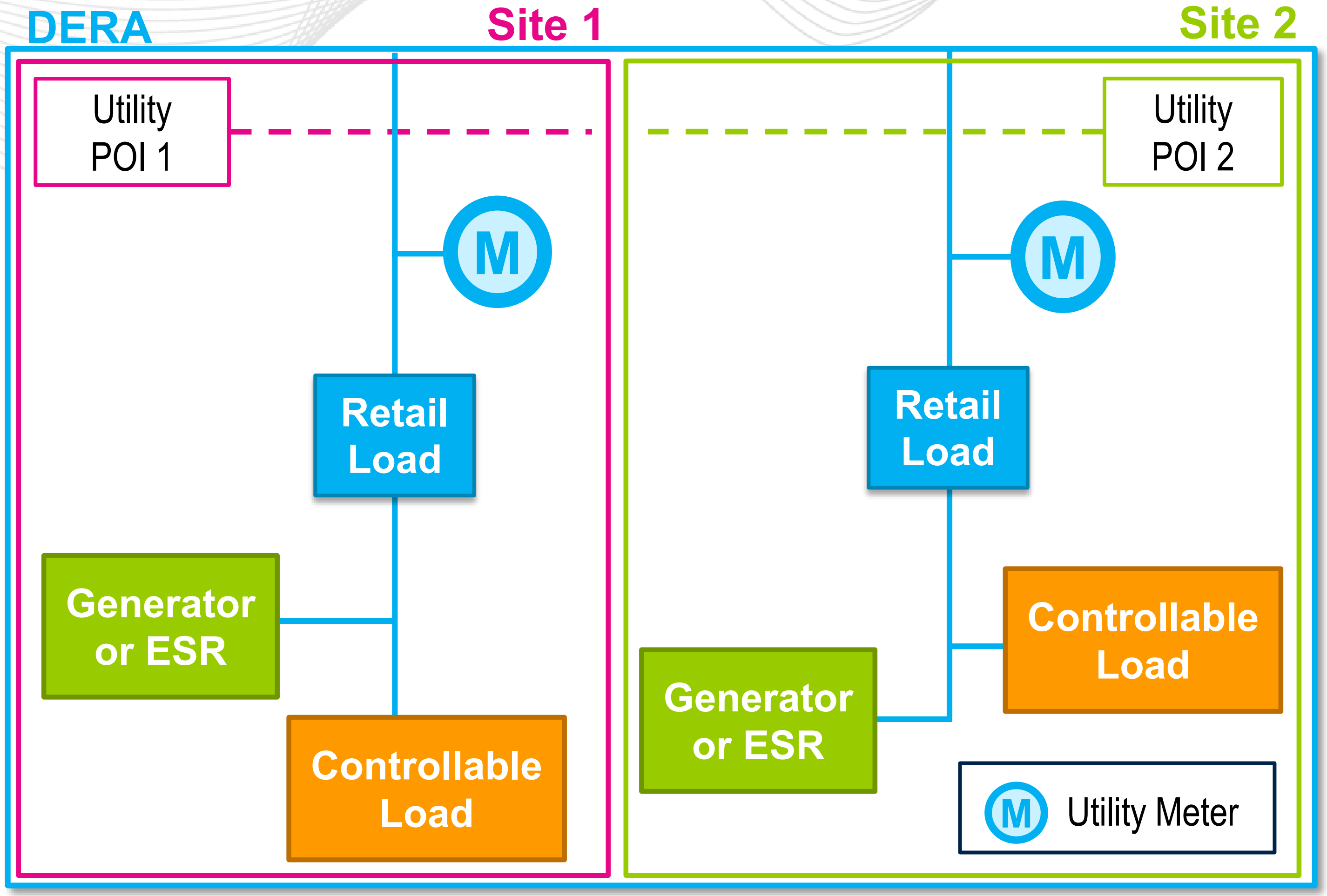
- A single distributed generator(s) or ESR at…
- Multiple distinct sites
- All sites co-located with retail customer load
- Sites may inject
- Can elect DRwDI **or** net injection BTMG **or** DR
- *Will explore both AS-only and comprehensive participation for this case*



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Use Case 6 – New

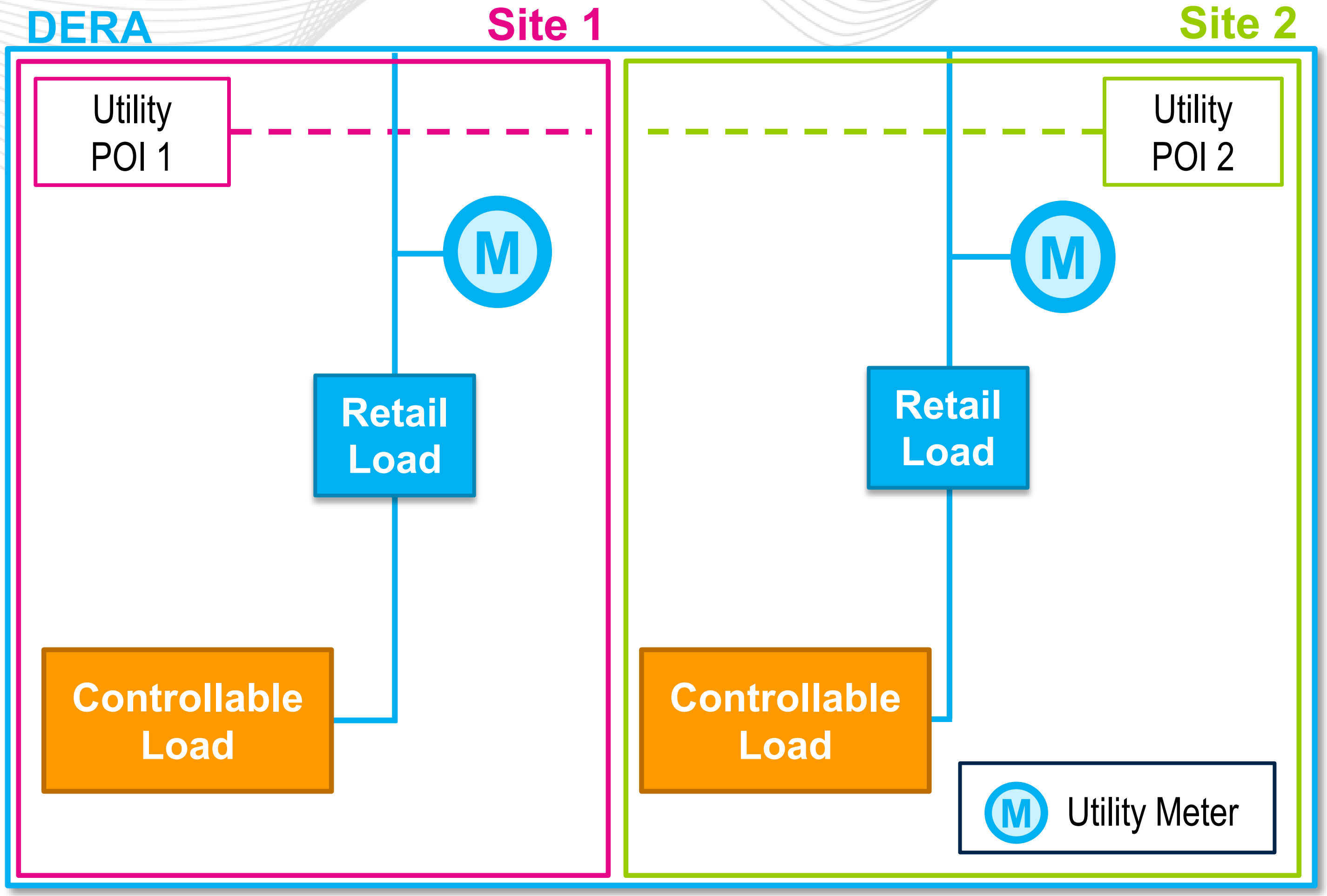
- Same composition and configuration as Use Case 4
- …but the single site is duplicated
- Sites may inject
- Can elect DRwDI **or** net injection BTMG **or** DR



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Use Case 7 – New

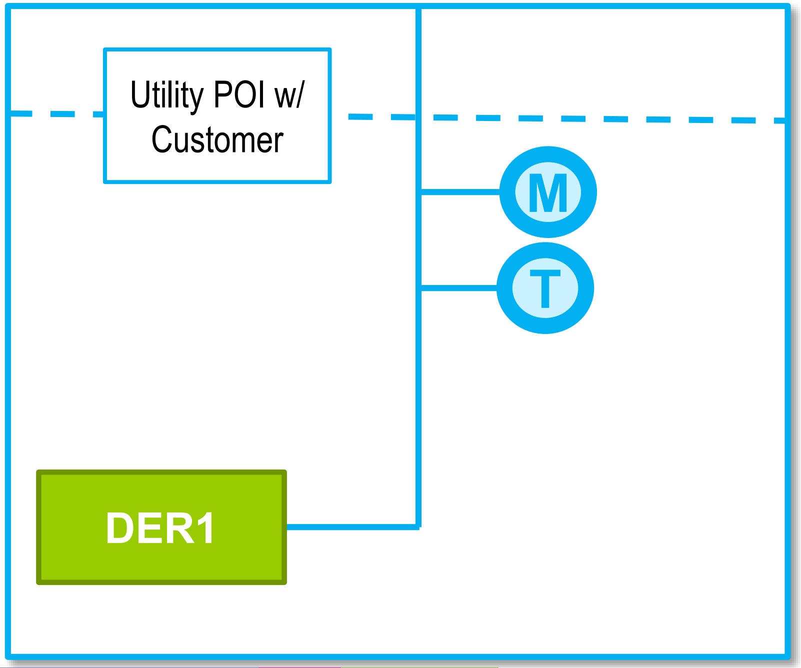
- A single controllable load at…
- Multiple distinct sites
- All sites co-located with retail customer load
- Has **only the DR option**—*no possibility of injection*



Note: This Meter represents status-quo utility interconnection, PJM telemetry or metering are discussed in a later slide.

Walkthrough: Use Case 1

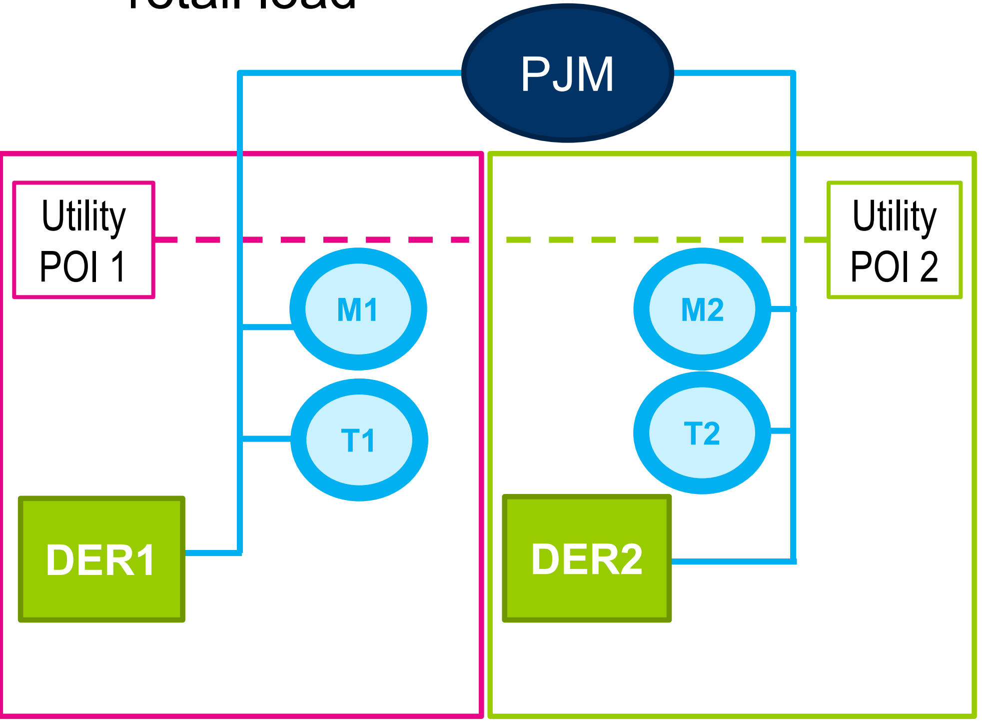
- A single distributed generator or ESR (single fuel type) at a…
- Single geographic site
- Participating as a single DERA
- Not co-located with retail load



Area	Proposal
Energy Market Participation Model	DERA Model, Gen Model or ESR Model ** depending on tech. ** Note: ESR DERA do not receive wholesale charging energy.
Capacity Capability	Calculated Status Quo based on technology - Generator: ICAP * eFORd (either unit-specific, or class average—see M-22, or RAA Sch. 5 Sec. B respectively) - Solar, Wind, or Battery: ELCC
M&V / Testing	Leverage existing business rules: - Generator: 1 hour test for ICAP - Solar, Wind, or Battery: relevant data per M-21 and M-21a
PAI	Expected: Capacity Commitment * BR Actual: PowerMeter data + Ancillary adjustments
Locational Requirements	(Energy, Ancillary) Maps to 1 primary location in PJM (DERA of 1 DER will always meet locational requirements) (Capacity) Can aggregate with other DER for a DER CP Resource within defined LDAs
Metering (Settlements)	Hourly MW values at M meter are submitted to PowerMeter
Telemetry	RT telemetry required for applicable markets

Walkthrough : Use Case 2

- A single distributed generator or ESR (single fuel type) at…
- Multiple geographically distinct sites
- No sites in DERA co-located with retail load

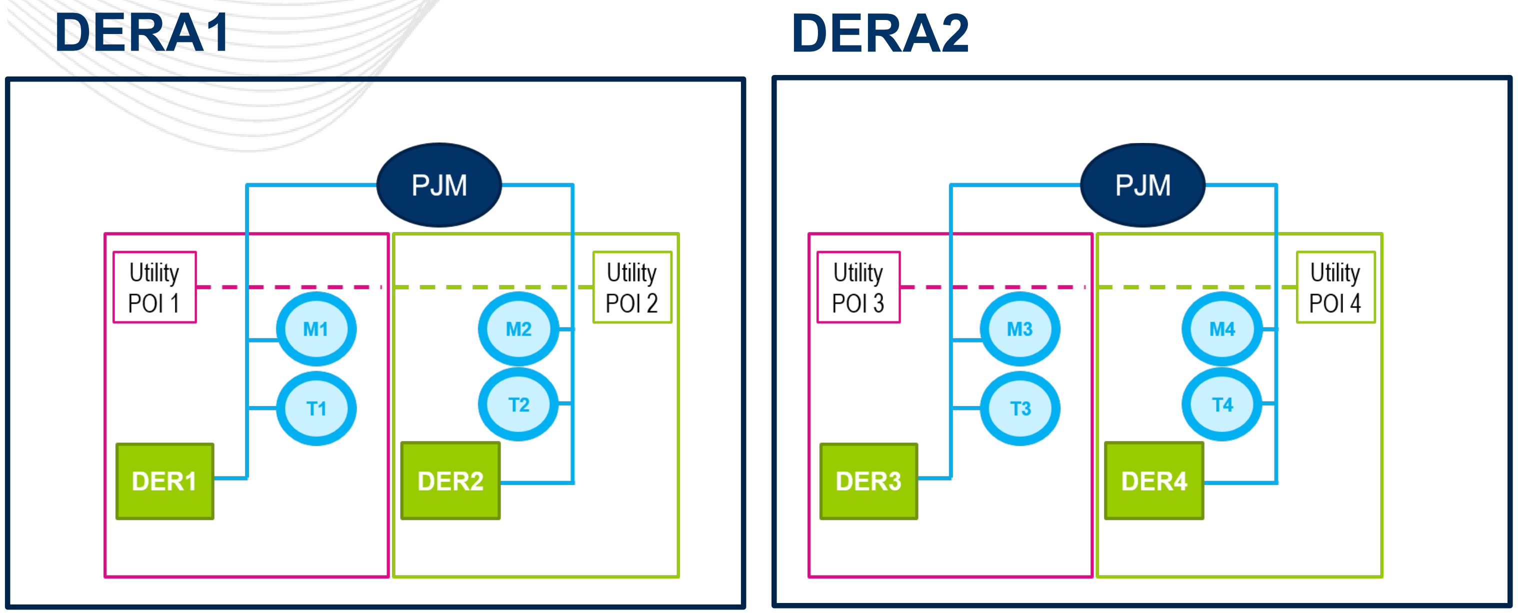


Area	Proposal
Energy Market Participation Model	Homogenous: DERA Model, Gen Model, or ESR Model, depending on technology present Heterogeneous: DERA Model
Capacity Capability	DERA Capability = DER1 + DER2 (prev. slide) Commitments allocated to DERA CP Resource level
M&V / Testing	M&V and testing at DER level. Leverage existing rules: - Generator: 1 hour test for ICAP - Solar, Wind, or Battery: relevant data per M-21, 21a
PAI	Expected: Capacity Commitment * BR at DER level, aggregated up to DERA and CP resource Actual: PowerMeter data for DERA + Ancillary adjustments
Locational Requirements	(Energy, Ancillary) Maps to 1 primary location in PJM (Ancillary Only) Can map across EDC footprint (Capacity) Can aggregate with other DER for a DER CP Resource within defined LDAs
Metering (Settlements)	Hourly MW values from each DER (M1 and M2) meter submitted to PowerMeter
Telemetry	RT telemetry required for DERA for applicable markets

- DERA1 and DERA2 are in DERA CP Resource
- All DER ICAP 5 MW and UCAP 4.8 MW therefore

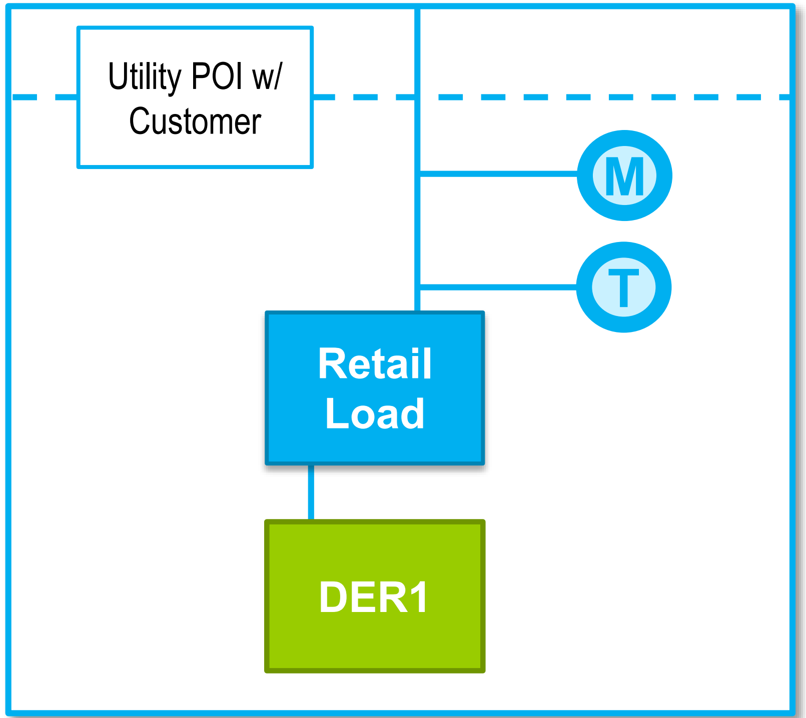
DERA1 & DERA2 = 9.6 MW capacity

- Offers into capacity for 19.2 MW and clears 17.2 MW, Allocate commitment down to DERA pro-rata ; 8.6MW and down to DER 4.3MW
- PAI: Actual-Expected; (DER1 Actual- Expected) + (DER2 Actual- Expected) + (DER3 Actual- Expected) + (DER4 Actual- Expected)
- Expected = Commitment *BR , Actual =PowerMeter Data



Walkthrough: Use Case 3

- A single distributed generator or ESR (single fuel type) at a…
- Single geographic site participating as a single DERA
- Site co-located with retail load



Area	Proposal
Energy Market Participation Model	DERA Model, or ESR model if energy storage
Capacity Capability **Details provided on the following slides.**	Option 1: Participate as BTMG Option 2: Participate as DR Option 3: FTM Option 4: Participate as Continuous (DRwDI) Resource
M&V / Testing	Based on technology type, see previous case
PAI	Expected: Capacity Commitment * BR Actual: PowerMeter data + Ancillary adjustments
Locational Requirements	(Energy, Ancillary) Maps to 1 primary location in PJM (DERA of 1 DER will always meet locational requirements) (Capacity) Can aggregate with other DER for a DER CP Resource within defined LDAs
Metering (Settlements)	Hourly MW values at M meter submitted to PowerMeter or DR Hub if relevant
Telemetry	RT telemetry required for DERA for applicable markets Individual resources do not need telemetry **(Ancillary Only) can submeter DER1 for regulation**

Use Case 3: Participation as BTMG Injection

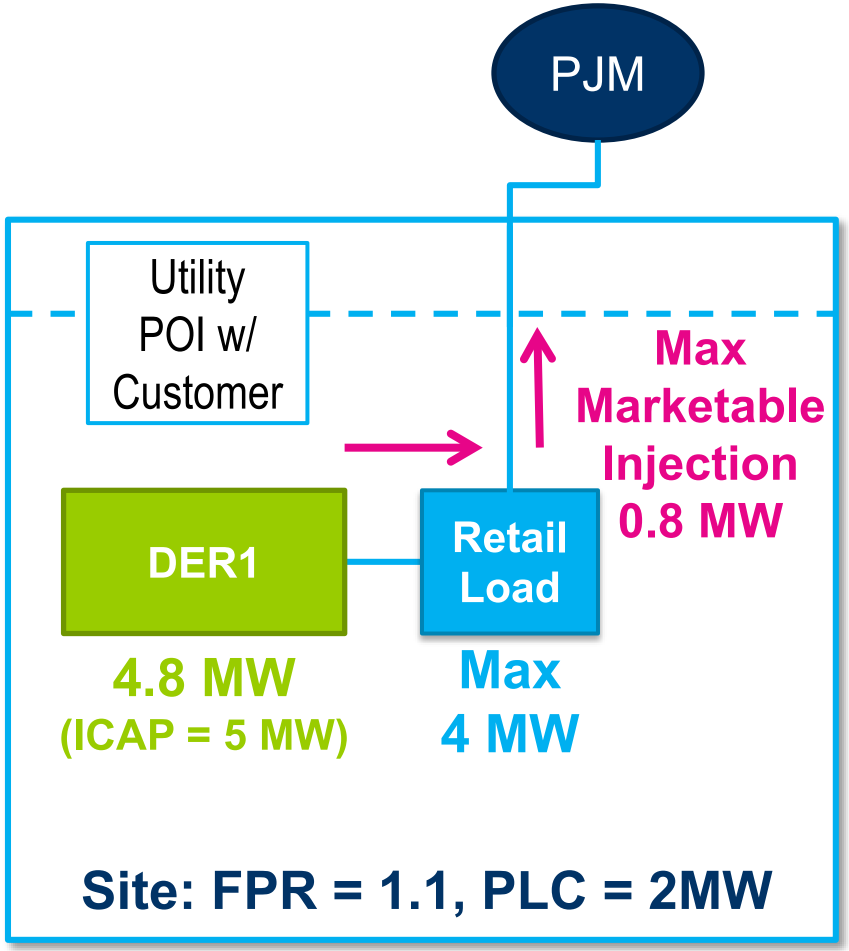
- **Retail Load = 4 MW max**
- **FPR = 1.1, PLC = 2 MW**
- **DER1 = 5 MW ICAP, 4.8 MW UCAP**

Option 1: BTMG = net injections only = 4.8 MW – 4 MW = **0.8 MW**

*Option 2: DR Only (resource cannot inject) = PLC * FPR = 2.2 MW*

Option 3: Bring resource front-of-meter = FTM = 4.0 MW

Note: "Injection" in this case refers to distribution injection, a capability that is to be studied and vetted by EDC prior to approval in Registration process.



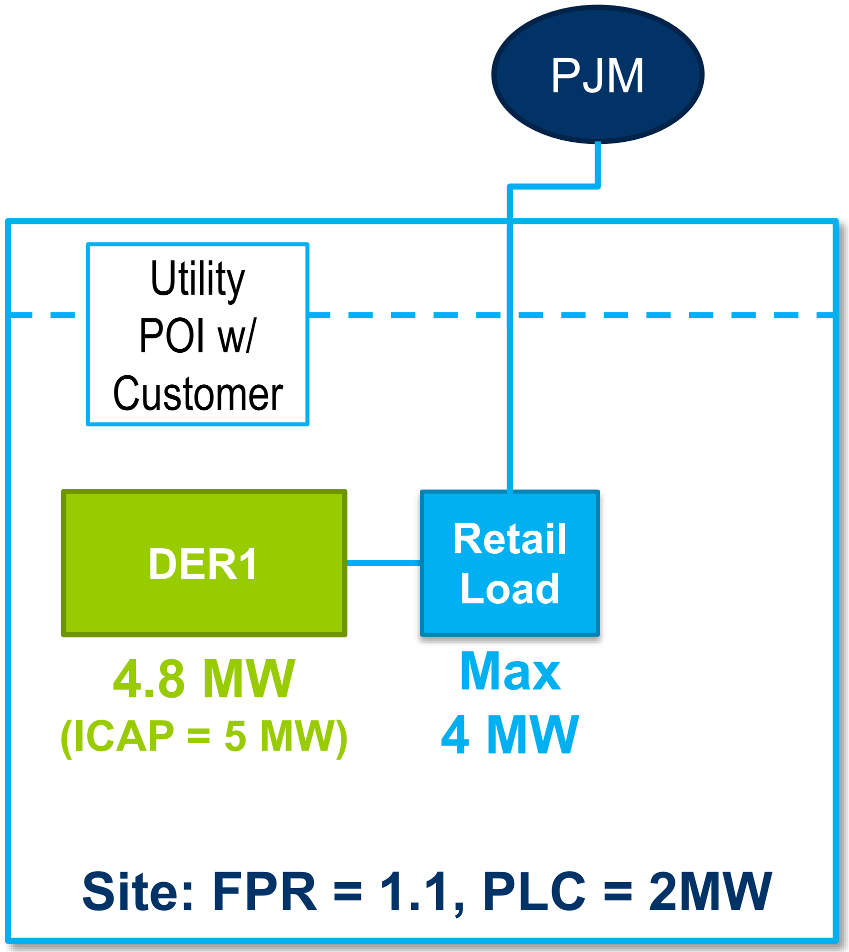
Use Case 3: Participation as DR-Only

- **Retail Load = 4MW max**
- **FPR = 1.1, PLC = 2MW**
- **DER1 = 5 MW ICAP, 4.8 MW UCAP**

Option 1: BTMG = net injections only = 4.8 MW – 4 MW = 0.8 MW

Option 2: DR Only (resource cannot inject) = PLC * FPR = **2.2 MW**

Option 3: Bring resource front-of-meter = FTM = 4.0 MW



Use Case 3: Participation as FTM

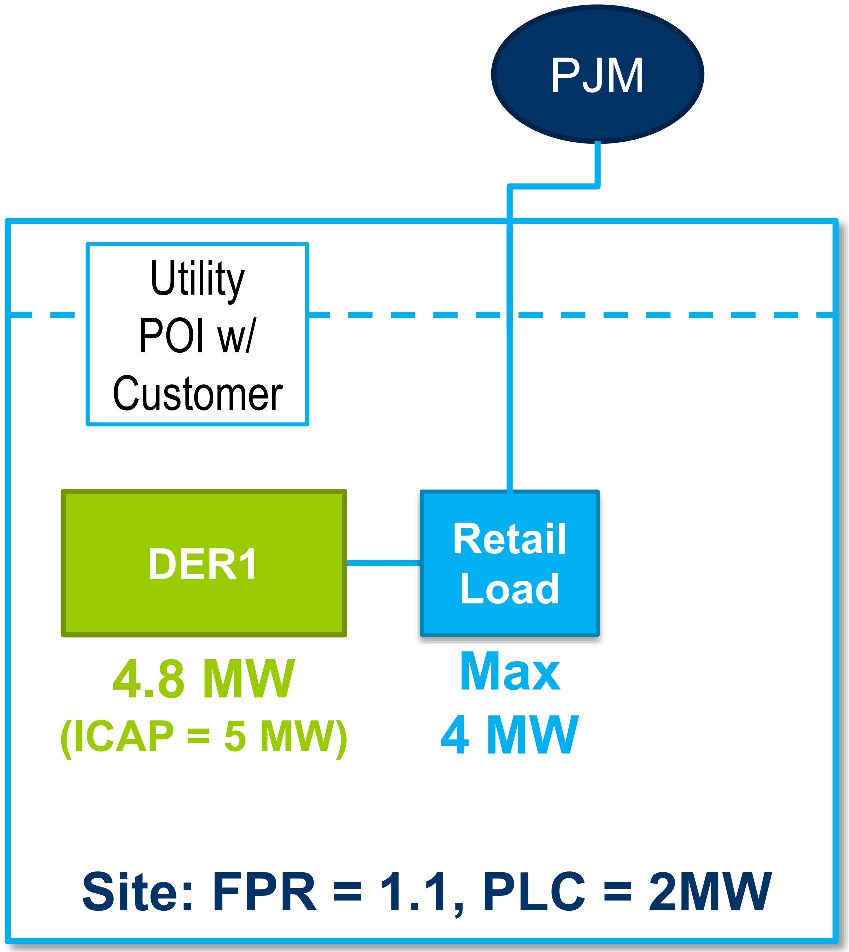
- **Retail Load = 4MW max**
- **FPR = 1.1, PLC = 2MW**
- **DER1 = 5 MW ICAP, 4.8 MW UCAP**

Option 1: BTMG = net injections only = 4.8 MW – 4 MW = 0.8 MW

*Option 2: DR Only (resource cannot inject) = PLC * FPR = 2.2 MW*

Option 3: Bring resource front-of-meter = FTM = **4.0 MW**

Note: FTM DER participating in Capacity are subject to MOPR and MSOC.

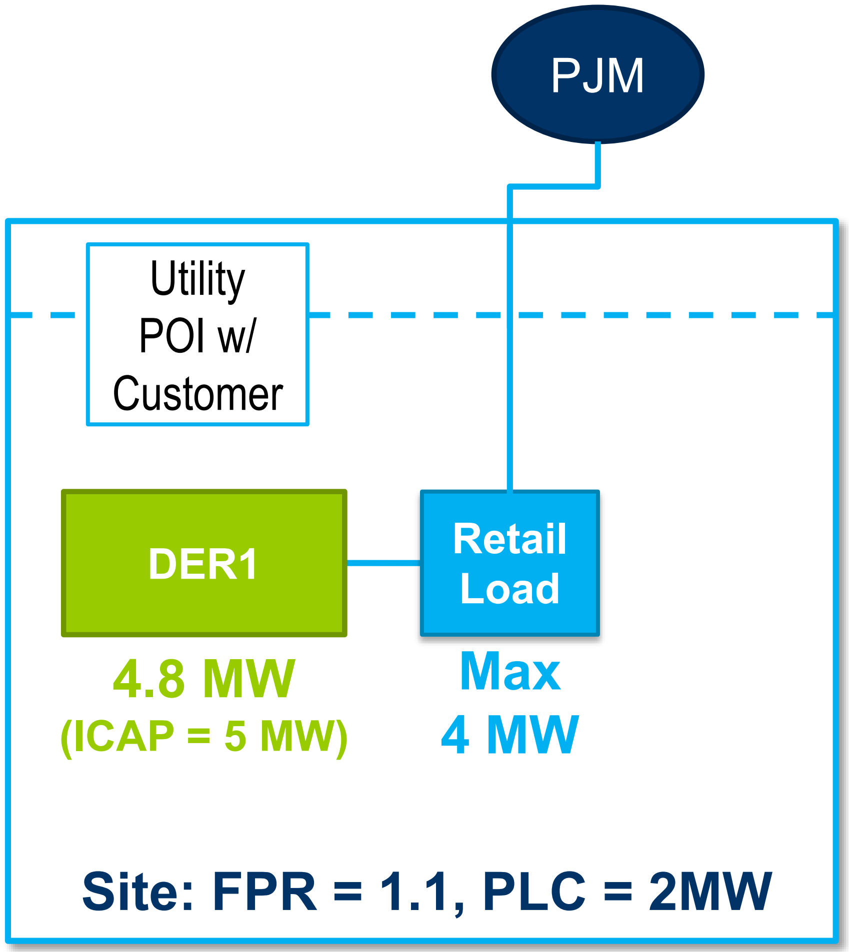


Use Case 3: Participation as Continuous (DRwDI) Resource

- **Retail Load = 4 MW max**
- **FPR = 1.1, PLC = 2 MW**
- **DER1 = 5 MW ICAP, 4.8 MW UCAP**

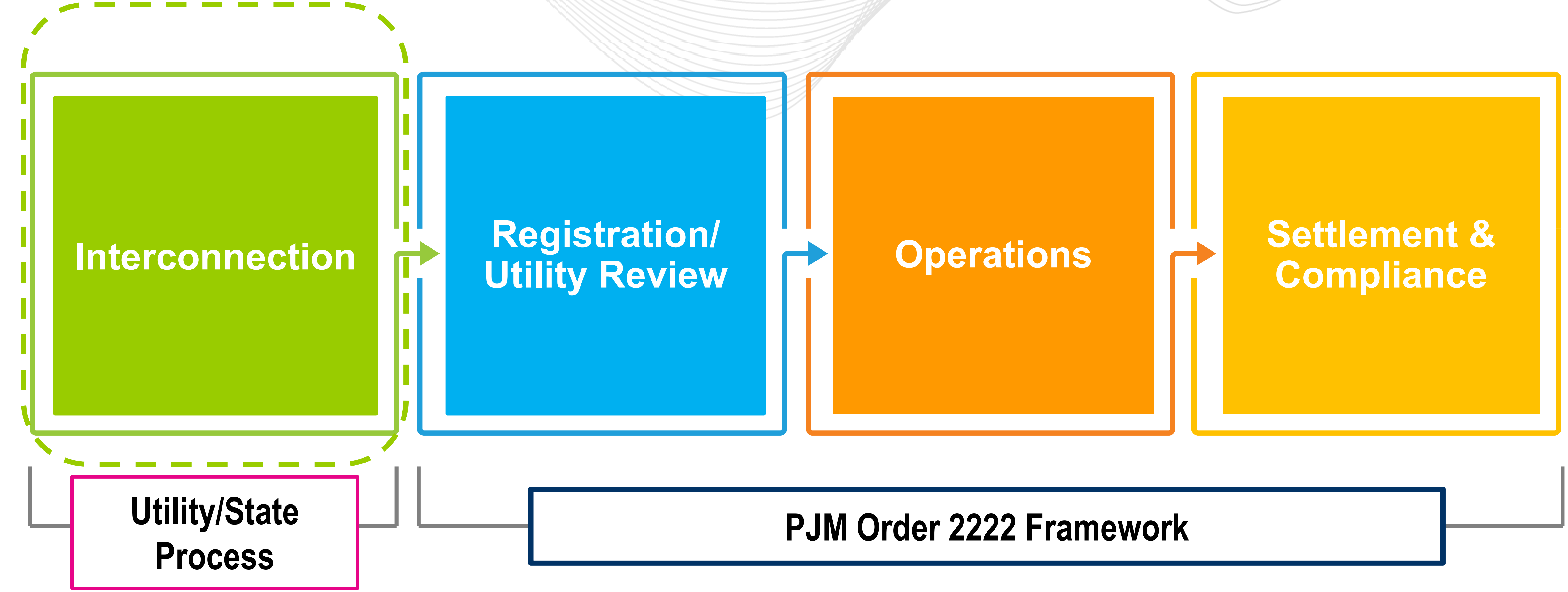
Option 4: Continuous DER

- All for load reduction (PJM), net load (retail) and injections (PJM) to be accounted for
- Two part calculation
  - DR: 2 MW PLC * FPR factor = 2.2 MW capability
  - Injection: 4 MW max load, 4.8 MW UCAP = 0.8 MW capability
- Total Capacity Capability= 3.0 MW
- Add back to PLC for PJM dispatch



Coordination	
DER Registration	• Utility Review Process • 60 Day timeframe for review • Addresses necessary review, data submissions and studies required
Modification of List of Resources	• Adding or Removing resources from a DERA will require a re-review of the aggregation for market participation • 60 Day timeframe for review
EDC Coordination	• Communications necessary for safety and reliability of the transmission and distribution systems • Overrides

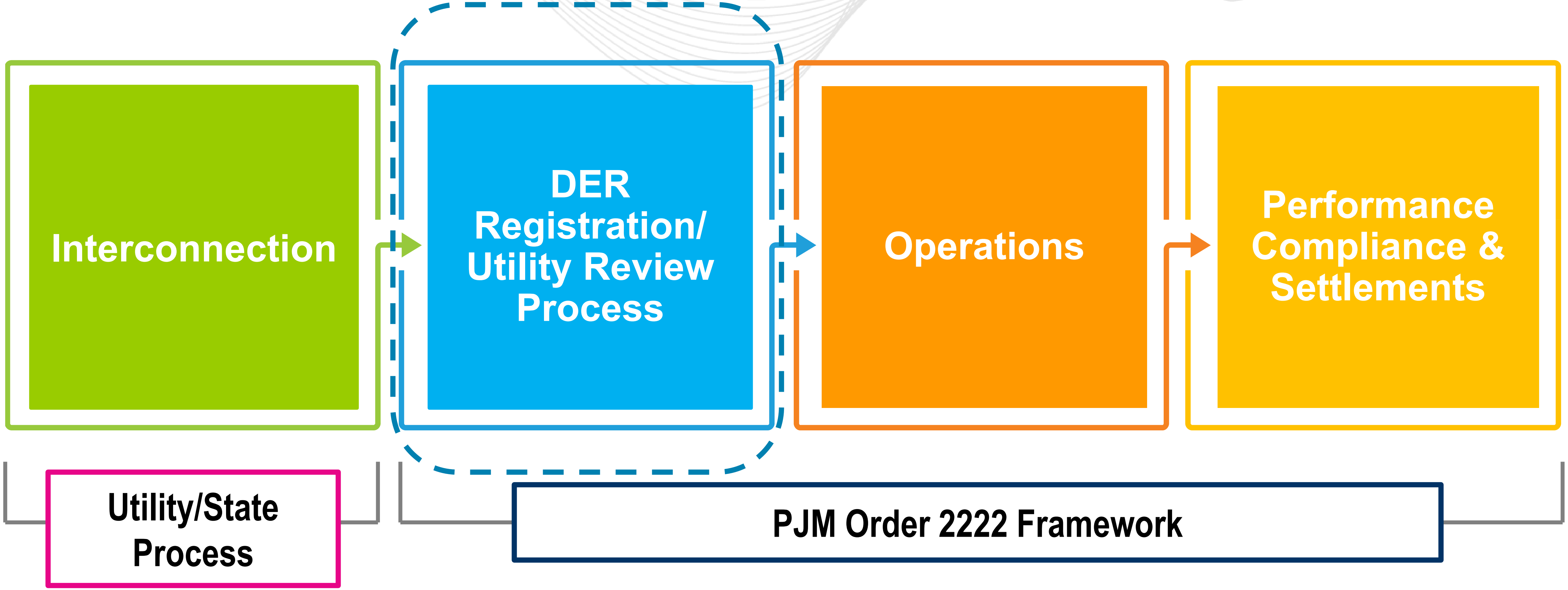
EDC Coordination- DERA Participation



Resources will go through their applicable state interconnection process prior to entering the PJM registration process

- Valid State IA will be needed for each underlying DER to operate as part of a DERA
- DERs will be required to follow all requirements within State IA
- Likely some exceptions for a valid State IA for Planned DER offering into forward capacity auctions
  - Interconnection agreements would still need to be in place prior to delivery year and DERA going operational

EDC Coordination- DERA Participation



- **DER Registration/ Utility Review Process: Process from DER Aggregator submission of DERs to participate in PJM's Market(s) in a DER Aggregation to PJM Approve/Denies DER Aggregation.**
  - Registration
  - Market Readiness
  - PJM Planning
  - Utility Review

Roles & Responsibilities

RERRA

- Small utility opt-in evidence
- Large utility opt-out evidence for Demand Response
- Additional DER requirements, managed through Interconnection

Aggregator

- Responsible for complying with all PJM business rules
- Registers individual DER & provides all necessary data/info. for aggregation
- Signs Market Participation Agreement
- PJM Member & Participates in PJM Markets

EDC

- Review certain DER data for accuracy
- Provide additional data for planning & market modeling
- Reliability review of aggregation

PJM

- Reviews DERA registration for completeness
- Establishes telemetry for DERA and verifies meter
- DERA Market modeling and readiness
- Approves/Denies registration
- Dispute resolution
- Signs market participation agreement

LSE

- (LSE) Notified that LSE customers are included in registration

DER Aggregation Registration and Review Process

DER Interconnection process complete* and met all applicable local and TO reqts.

*if required by state/local utility

Planned DER: PJM-approved offer plan required prior to bidding into RPM auction. Will require Aggregator to complete registration prior to delivery year.

DERA Registration Submitted - **aggregator**

PJM and **EDC** are notified of submission

Data Review

60 Days

Data complete & no reliability review needed (fast track)

EDC Reliability Review

"Data Review Period"

- PJM reviews application for completeness and verifies markets for DERA participation
- EDC Reviews Information for accuracy
- Review application is eligible under RERRA requirements & Opt-in/out evidence
- Meter configs. reviewed
- EDC provides locational information
- EDC identifies additional reliability review/study, as needed
- PJM reviews the aggregation in the Planning model updates

"Reliability Review Period"

- EDC to perform any necessary reliability studies for aggregation's market participation
- EDC to perform any additional locational data requirements

PJM will approve/ deny registration

PJM | EDC | AGG

DERA Approval Next steps

Aggregators will have additional items required prior to DERA Operations in PJM. These can be working in parallel/during registration process or after registration process.

- DERA <> PJM telemetry set up
- Market testing
- Market Gateway acct.
- EMS modeling
- Power Meter verification

TO will need to reflect DERA resources in updated transmission model to show DERs as an aggregated model for Planning RTEP studies.

Registration Data

Category	Data Requirements	Aggregator	EDC	PJM	LSE
Registration	Registration Start/End date	Submits	Views Data	Used for Market status	Views Data
Registration	Registration Status	Submits	Views Data	Used for Market status	Views Data
Registration	Market Participation (Capacity, Energy, Ancillary)	Submits	Used for reliability study review	Used for Market status	Views Data
Registration	DER type	Submits	Views Data	Used for Market calculcation/requirements	
Registration	DER technology	Submits		Used for Market calculcation/requirements	
Registration	Transmission Zone	Submits	Approve/Deny	Used for resource mapping	
Registration	EDC	Submits	Approve/Deny	Used for resource mapping	
Registration	EDC account information	Submits	Approve/Deny	Used to validate no Wholesale double counting (same resource participating in 2 aggregations)	
Registration	Site Address	Submits	Approve/Deny	Used to validate no Wholesale double counting (same resource participating in 2 aggregations)	
Registration	EDC Interval Meter (if applicable)	Submits	Approve/Deny		
Registration	RERRA Evidence	Submits	Approve/Deny	Used to determine market participation eligibility	
Registration	Retail Agreements	Submits	Reviews	Used to determine market participation eligibility and double counting	
Registration	Expected participation hours	Submits	allows EDC to know when resource is expected to be in the market		Views Data
Registration	EDC Interconnection ID- Approved EDC Inerconnection	Submits	Approve/Deny	Used to determine market participation eligibility	

Expect to leverage functionality similar to DR registrations (DR Hub)
*Finalized list of data needs will continue to be worked though implementation, large list of data items provided in proposal for understanding of general data requests.

Registration Data

Category	Data Requirements	Aggregator	EDC	PJM	LSE
Resource Set up	PJM Telemetry setup: Reference to telemetry code for SCADA link	Submits	review	approve/deny	
Resource Set up	Primary Location Poiint (pnode)	Submits	submits/updates - approve/deny	Used for resource mapping	
Resource Set up	Energy Pricing Point - pnode. One resource may be mapped to more than 1 pnode	review	submits/updates - approve/deny	Used for resource mapping	
Resource Set up	Max Load (kW) (Max hourly load over prior 12 months)	Submits	Views Data	Used for market participation capability	
Resource Set up	Max Injection (kW) (Max injection amount based on interconnection process)	Submits	Views Data	Used for market participation capability	
Resource Set up	Max Market Eligibility (Maximum amount that will be offered in the market)	Submits	Views Data	Used for market participation capability	
Resource Set up	Load Reduction Method (Indicate load reduction capability (kw) for each load reduction capability (HVAC, Refrigeration, Generation, Lighting, Industrial Process, etc.))		Views Data	Used for market participation capability	
Resource Set up	Generator Details (nameplate capacity, inverter type, installation date)	Submits	Views Data	Used for market participation capability	
Resource Set up	Peak Load Contribution (PLC) (Used to determine capacity nomination for DR related DER)	Submits	Views Data	Used for market participation capability	
Resource Set up	Loss Factor (if applicable)	Submits	Views Data	Used for market participation capability	

Expect to leverage functionality similar to DR registrations (DR Hub)
*Finalized list of data needs will continue to be worked though implementation, large list of data items provided in proposal for understanding of general data requests.

Registration Data

Category	Data Requirements	Aggregator	EDC	PJM	LSE
Planning Data	Maximum AC output (gross nameplate capability)	Submits	Approve/Deny	Review	
Planning Data	~~Interconnected distribution line identification~~	~~NA~~	~~Submits~~	~~PJM plans to track distribution location and work with Transmission Owner to update transmission model, as necessary (Quality Assurance).~~	
Planning Data	PJM Planning Model Bus ID that the DER aggregation is fed from*	NA	Submits	Used for tracking any distributon *changes that need to be updated in PJM Models*	
Planning Data	Ride through capability enabled (Yes/No)	Submits	Approve/Deny	Used for PJM Planning reviews	
Planning Data	Voltage control enabled (Yes/No)	Submits	Approve/Deny	Used for PJM Planning reviews	

Category	Data Requirements	Aggregator	EDC	PJM	LSE
Utility Review	EDC reliability issue: EDC provides input to PJM if DER should not be allowed to participate because it will create a reliability issues for Distribution System		Submits	Uses this information for approving/denying registration	

Expect to leverage functionality similar to DR registrations (DR Hub)
*Finalized list of data needs will continue to be worked though implementation, large list of data items provided in proposal for understanding of general data requests.

- Examples of Registrations

Use Case 1: Solar attached to distribution system approved through utility interconnection process

NEM, PURPA or other retail agreement that impacts participation

Registration								Resource/Location									
DER Provider	StartDate	EndDate	Resource Type	Markets	EDC	Zone	Status	EDC Acct Number	Name	Address, city, state, zip	Pricing Point	EDC Interconnection Number	Agreements	Type	Max Load	Max Injection (kW)	Max Offer (kW)
DER King	6/1/2021	5/31/2022	FtMDER	Capacity, energy, SR, Reg	PECO	PECO	Pending	012345	Ridge solar	12 Maple, Smithville, PA, 19809				Solar	0	500	500

Legend - background color

White - DER Provider provides the data in the registration

Yellow - EDC reviews and approves/denies the data submitted by DER Provider

Green - EDC provides the data

System - Grey

Plan to have PJM assign a default based on zip code when size < X kW. EDC to review and update.

Use Case 2: Aggregate solar attached to distribution system approved through utility interconnection process

Registration								Resource/Location									
DER Provider	StartDate	EndDate	Resource Type	Markets	EDC	Zone	Status	EDC Acct Number	Name	Address, city, state, zip	Pricing Point	EDC Interconnection Number	Agreements	Type	Max Load	Max Injection (kW)	Max Offer (kW)
DER King	6/1/2021	5/31/2022	FtMDER	Capacity, energy, SR, Reg	PECO	PECO	Pending	012345	Ridge solar	12 Maple, Smithville, PA, 19809		89-02-1a		Solar	0	500	500
								34251	valley solar	9 Oaks, Jonestown, PA, 19814		67-09-2b		Solar	0	300	300
														Total	0	800	800

Legend - background color

White - DER Provider provides the data in the registration

Yellow - EDC reviews and approves/denies the data submitted by DER Provider

Green - EDC provides the data

System - Grey

Max offer amount in the markets

Registration aggregation – still need to work out the specifics on types of resources that go on same registration

Use Case 3: Battery attached to distribution system approved through utility interconnection process

Registration								Resource/Location									
DER Provider	StartDate	EndDate	Resource Type	Markets	EDC	Zone	Status	EDC Acct Number	Name	Address, city, state, zip	Pricing Point	EDC Interconnection Number	Agreements	Type	Max Load	Max Injection (kW)	Max Offer (kW)
DER King	6/1/2021	5/31/2022	FtMDER	Reg	PECO	PECO	Pending	656589	Ash Storage	2 farm rd, ashville, PA, 19912		89-02-1a		Battery	400	400	400

Legend - background color

White - DER Provider provides the data in the registration

Yellow - EDC reviews and approves/denies the data submitted by DER Provider

Green - EDC provides the data

System - Grey

Will only participate in the Regulation market

Registration will indicate market eligibility

Use Case 4: Industrial customer with load reduction capability and generation approved through utility interconnection process

Registration								Resource/Location										
DER Provider	StartDate	EndDate	Resource Type	Markets	EDC	Zone	Status	EDC Acct Number	Name	Address, city, state, zip	Pricing Point	EDC Interconnection Number	Agreements	Type	Max Load	Max Injection (kW)	Max Offer (kW)
DER Queen	6/1/2021	5/31/2022	DRwI	Capacity, energy, SR, Reg	PECO	PECO	Pending	656589	Metal Fabrication	2 farm rd, ashville, PA, 19912		89-02-1a		Industrial Process 300kW Gen: 200 kw	300	200	500

Assume additional DR information based on status quo is included in the Registration & Resource/Location information.

Legend - background color

White - DER Provider provides the data in the registration

Yellow - EDC reviews and approves/denies the data submitted by DER Provider

Green - EDC provides the data

System - Grey

EDC visibility for injection reason

Illustration – still need to work out whether to model as one or two resources, locational requirement, and specifics for each market

Use Case 5: Home with solar and battery approved through utility interconnection process

Registration								Resource/Location									
DER Provider	StartDate	EndDate	Resource Type	Markets	EDC	Zone	Status	EDC Acct Number	Name	Address, city, state, zip	Pricing Point	EDC Interconnection Number	Agreements	Type	Max Load	Max Injection (kW)	Max Offer (kW)
DER Queen	6/1/2021	5/31/2022	DRwl	Reg	PECO	PECO	Pending	656589	Joe's house	2 main st, pottstown, PA, 19912		89-02-1a		Gen: solar 5 kw, battery 2 kw	7	5	2

Assume

Additional DR information based on status quo is included in the Registration & Resource/Location information.

Solar used to offset load not eligible for wholesale revenue

Legend - background color

White - DER Provider provides the data in the registration

Yellow - EDC reviews and approves/denies the data submitted by DER Provider

Green - EDC provides the data

System - Grey

Only battery participates in wholesale regulation market

Agreement type may impact wholesale market participation options

From Order 2222…

- Each RTO/ISO to revise its tariff to specify that distributed energy resource aggregators must update their lists of distributed energy resources in each aggregation (i.e., reflect additions and subtractions from the list) and any associated information and data.
  - Distributed energy resource aggregators will not be required to re-register or re-qualify the entire distributed energy resource aggregation.
  - The impacts of modifications may often be minimal, an abbreviated review process should be sufficient for the distribution utility to identify the cases where an addition to the list of resources might pose a safety or reliability concern.
  - Could occasionally indicate changes that justify restudy of the full distributed energy resource aggregation

- Aggregators that are modifying an existing DERA will need to submit modifications to the utility review process
- Adding/Removing a DER to a DERA
  - 60 days review process; same review process as origination on DERA which is still an abbreviated process in comparison to generation changes
  - If DERA is part of a DERA CP resource, these aggregations will be active for the full delivery year and will not be able to be modified.
  - DERA changes can be made on a quarterly basis to all any potential updates to be reflected into PJM models.

EDC Coordination- DERA Participation

Interconnection

DER Registration/ Utility Review Process

Operations

Performance Compliance & Settlements

Utility/State Process

PJM Order 2222 Framework

- Bid parameter updates
  - Updates to the full dispatchable economic range for an aggregation to operate reliably
  - Updated any time from before day ahead through real-time
  - Eco Min/Max
- Real-time override
  - A utility override of a PJM dispatch signal to DERA
  - Utility can determine the method of how this is achieved

- Each EDC has its own reliability criteria
  - These are not determined by PJM, nor monitored or controlled by PJM.
  - Planned system conditions requiring updated bid parameters should be coordinated in advance.
  - Need for updated real-time bid parameters or overrides to maintain reliability can be the result of (but not limited to) unplanned outages, safety, or load beyond forecasted expectations.
  - Real-time overrides are expected to be abnormal and are tracked. Routine overrides may result in re-evaluating market participation levels.
  - EDC maintains sole responsibility for the reliable operation of the distribution system at all times and always maintains authority to override PJM's market dispatch.

3 Timeframes for EDC Updates & Overrides

1. **Registration / Utility Review Process**: Prior to approving an aggregation for market participation, EDCs review and approve a dispatchable range for the proposed aggregation.
   – Aggregations submitting ranges the EDC cannot reliably expose to PJM on a "normal" basis should be denied (or modified).
2. **Day-Ahead:** Prior to day-ahead submittal, EDCs and Aggregators should coordinate an agreed upon range of MW dispatch per hour for DERA to submit to market.
   – MW levels impermissible by the EDC shall not be submitted in ECOMIN/ECOMAX.
3. **Real-Time:** For reliability concerns, any action the EDC deems necessary shall be executed by the aggregate.
   – EDCs should provide explanation after the fact as to the reliability concern and need to override for both PJM and the Aggregator.
   – This transparency will be useful for understanding potential persistent issues with an aggregation's operations.

Note: DERAs are not eligible for LOC or PAI excusals due to EDC override and will be subject to any applicable deviation changes / penalties.

- EDC should coordinate with aggregator on planned maintenance and other distribution work that will impact dispatchability of DER/DERA prior to day-ahead to allow aggregator to accurately reflect DERA capability in the market.
- PJM expects economic parameters from the aggregator to be in the form of a dispatchable range verified by the EDC prior to submittal.
- Ideally, day-ahead bid parameters will match those in real-time

- PJM expects to dispatch an aggregation within it's agreed upon range (ecomin to ecomax), based on PJM system needs and economic dispatch, unless there is an EDC declared condition for an override.
  - If an override is required by the EDC, the aggregator shall follow EDC dispatch direction and update their economic parameters accordingly in PJM Markets
  - PJM markets and pricing will react based on the aggregation's submitted parameters
- The EDC can require additional controls for distribution reliability within the local interconnection process (override: registration).

Operations Coordination

Day Ahead bid parameter update

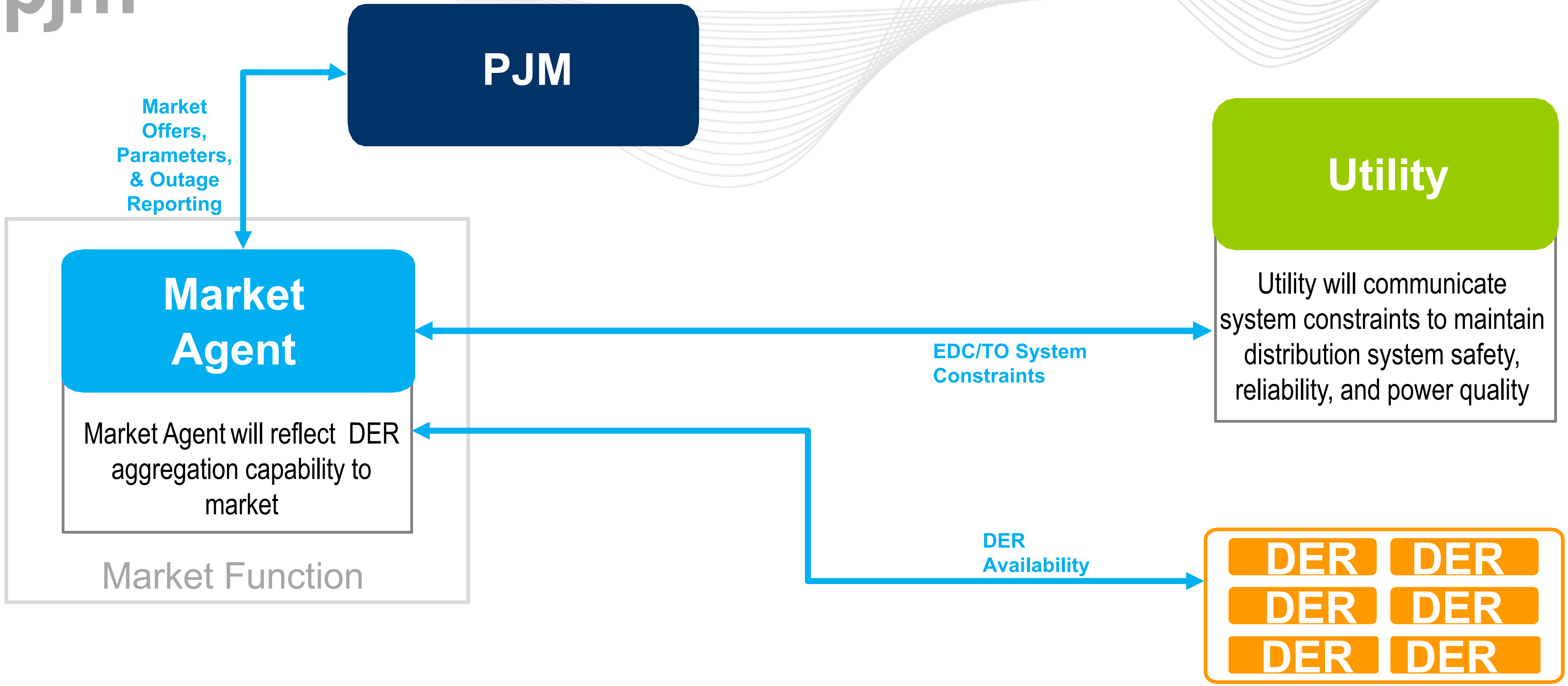
Timing	Step 1	Step 2	Step 3
Prior to Day Ahead Run (11:00)	**EDC** Notify Aggregator of any Ops Limitations	**DERA** Submits Market Bids to PJM	**PJM** Clears DERA based on updated bid-in parameters
After Day Ahead Run (13:30)	**PJM** Provide Aggregator and Utility (TBD) with DA schedule	**EDC** Receives DA Schedule (TBD) **DERA** Receives DA Schedule	**EDC** Submits any pre-dispatch bid parameter updates for unplanned outages and/or transfers.
Re-Bid and Intraday (14:15)	**DERA** Provide updates to allowable parameters to PJM	**PJM** Receives parameters, dispatches based on updated parameters, and communicates response	
DER Dispatch	**DER DISPATCHER** Executes require dispatch through DER telemetry	**PJM** Receives dispatch confirmation **EDC / DERA** Receives dispatch confirmation	**EDC** Submits or executes any post-dispatch overrides for unplanned outages and/or transfers.

Real-time bid parameter update

Real-time override

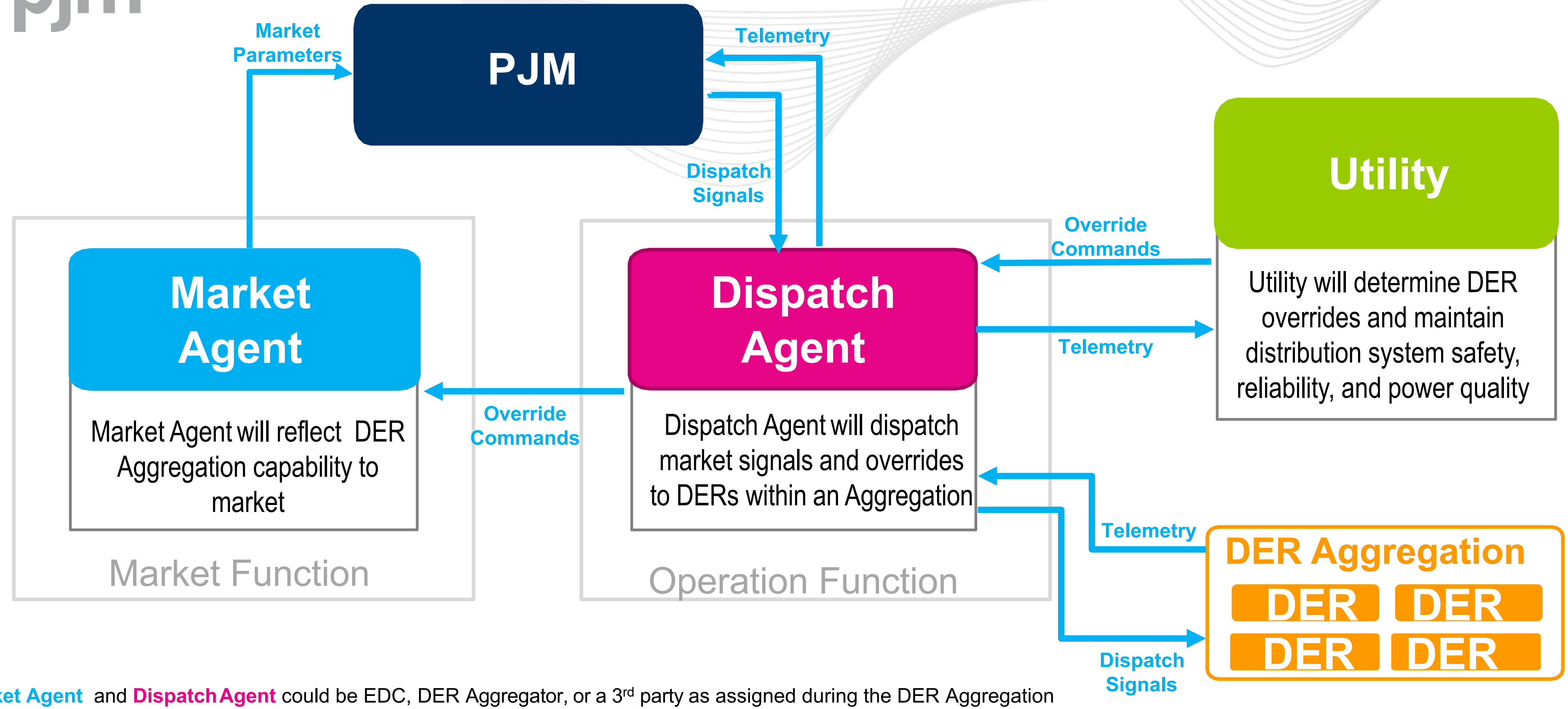
Updates to bid parameters should be done prior to Day Ahead, when possible. Bid parameters shall be updated in real-time, as needed, especially if an override to dispatch instructions for unplanned outages or reliability is required.

DERA Day-Ahead Wholesale Market - Communications Model



- **Market Agent** could be EDC, DER Aggregator, or a 3rd party as assigned during the DER Aggregation registration process in accordance with RERRA / PUC and Utility requirements.
- Existing **PJM** to Transmission Operator communications remain in place but are not shown in this model.
- This model represents necessary **PJM** communications but is not necessarily inclusive of all communications required by the utility

DERA Real-Time Wholesale Market - Operations Model



- **Market Agent** and **Dispatch Agent** could be EDC, DER Aggregator, or a 3rd party as assigned during the DER Aggregation registration process in accordance with RERRA / PUC and Utility requirements.
- Existing **PJM** to Transmission Operator communications remain in place but are not shown in this model.
- This model represents necessary **PJM** communications but is not necessarily inclusive of all communications required by the utility