# Order 2222 Design Discussion (part 2)

PJM Staff

DIRS

April 27, 2021

- 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 provide an informational filing containing a detailed stakeholder process schedule within 30 days – May 10, 2021

- And submit status reports every 90 days thereafter until the date that PJM submits its compliance filing.
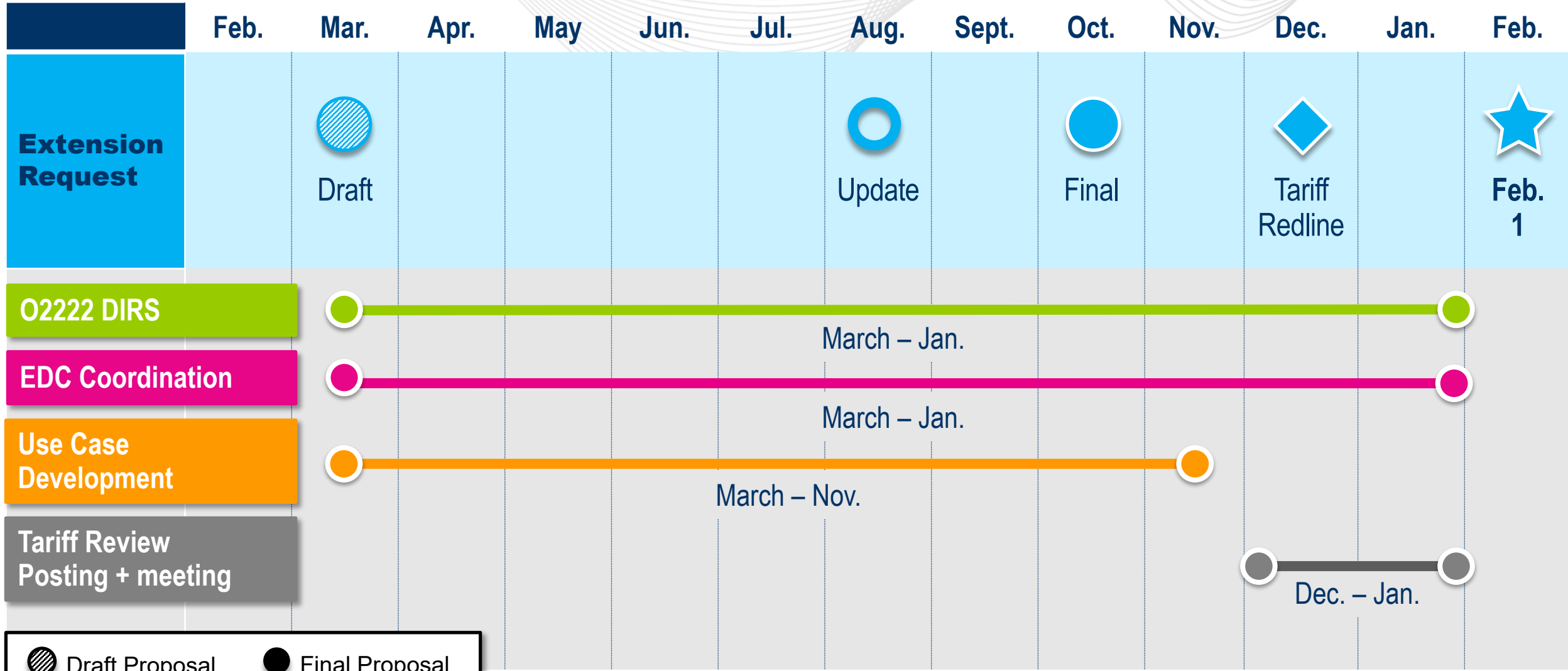
- Presenting PJM's high-level holistic design approach and additional areas that need to be further defined

  – PJM is continuing to iterate on the design for DER aggregations to comply with FERC Order 2222

  – Continue to receive feedback from stakeholders and update proposal based on that feedback

  – Areas of large differing opinions from stakeholders will continue to be worked in DIRS

- Material has been updated in this presentation with additional detail *only in* sections that will be covered for the first time in this meeting

  – Market Design (Min/Max Size Requirements), Settlement, and Coordination

- Updates to sections covered in the 3/31 DIRS will be provided to stakeholders as we iterate on the proposal in the DIRS.

  – Stand alone presentations have been posted for additional education on areas from last meeting

Design Items for today's discussion

DERA Jurisdiction & Interconnection	Operations	Market Design	Settlements	Coordination
		1. Min./Max. Size Requirements	1. Metering Configuration 2. Settlement requirements 3. Double Counting Services 4. Use case development	1. DER Registration 2. EDC Coordination 3. Modification to List of Resources

4/27 DIRS review will start on Slide 65 of this presentation

Order 2222 Design Discussion
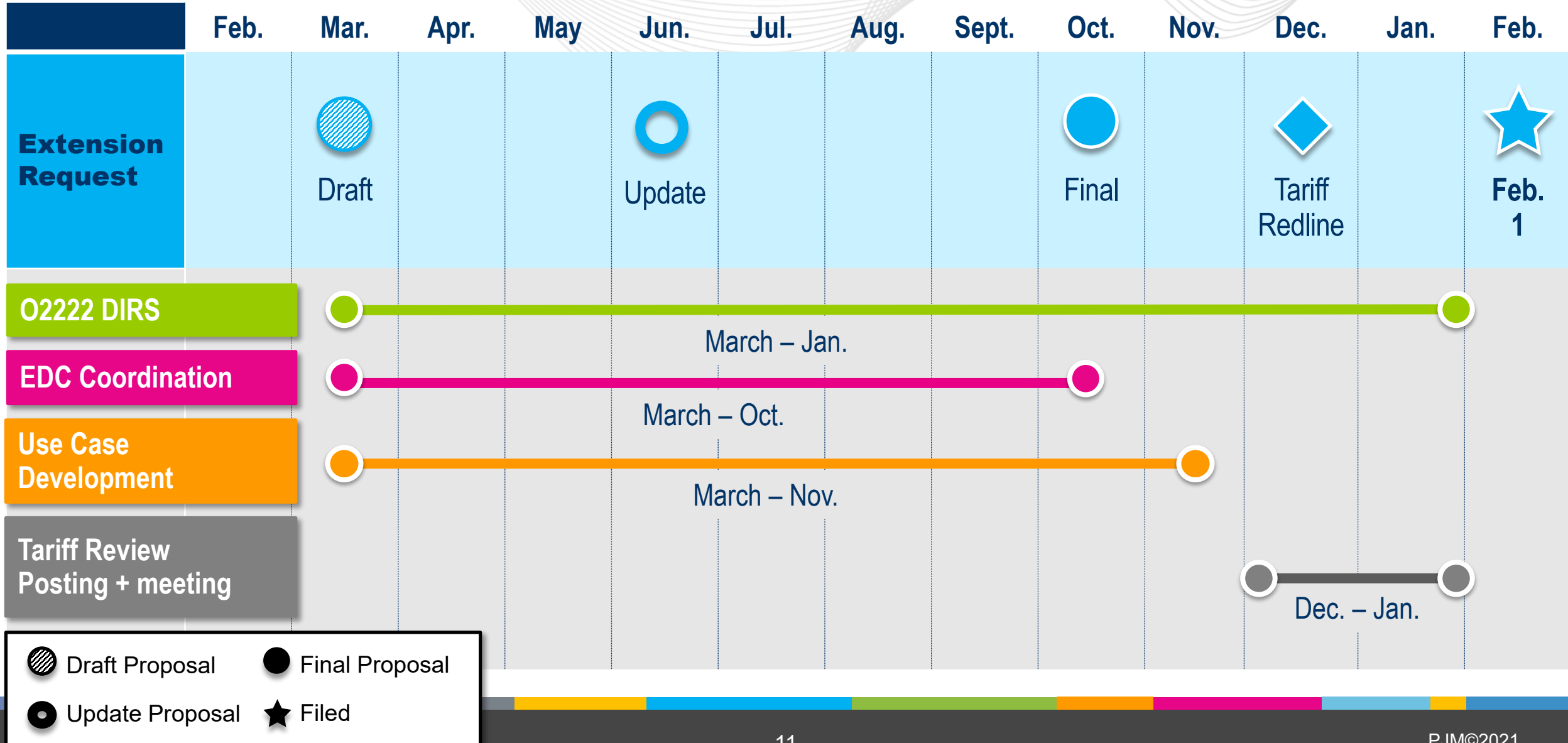
PJM Staff

DIRS

3/31/2021

- Presenting PJM's high-level holistic design approach and additional areas that need to be further defined
    - PJM is continuing to iterate on the design for DER aggregations to comply with FERC Order 2222
    - Continue to receive feedback from stakeholders and update proposal based on that feedback
    - Areas of large differing opinions from stakeholders will continue to be worked in DIRS

- 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);

- 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).

Extension Timeline

| | Feb. | Mar. | Apr. | May | Jun. | Jul. | Aug. | Sept. | Oct. | Nov. | Dec. | Jan. | Feb. |

Extension Request
Draft — Update — Final — Tariff Redline — Feb. 1

O2222 DIRS
March – Jan.

EDC Coordination
March – Oct.

Use Case Development
March – Nov.

Tariff Review Posting + meeting
Dec. – Jan.

Draft Proposal   Final Proposal
Update Proposal   Filed

- 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

DERA Jurisdiction & Interconnection	Operations	Market Design	Settlements	Coordination
1. Interconnection 2. Market Participation Agreements 3. Opt-in for Small Utilities	1. Locational Requirements 2. Distribution Factors 3. Telemetry 4. Operational Needs	1. Market Participation Model 2. Type of Technology (Homogenous / Heterogeneous) 3. Bidding Parameters 4. Min./Max. Size Requirements	1. Metering Configuration 2. Settlement requirements 3. Double Counting Services 4. Use case development	1. DER Registration 2. EDC Coordination 3. Modification to List of Resources

- **Distributed Energy Resource (DER):** any resource located on distribution, or distribution sub-system. Resource types include but not limited to Demand Response, Distributed Generation, Energy Storage, Electric Vehicles, & Energy Efficiency

- **Demand Response (DR):** any activity used to reduce load for the wholesale market

- **DER Aggregation (DERA):** An aggregation of one or more DER participating together in PJM Markets

- **DER Aggregator**: Market Participant for DERA

- 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)*

DERA Jurisdiction & Interconnection

- PJM will not have jurisdiction of the interconnection of DER resources, but rather 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 and be eligible to participate in PJM's wholesale market.

  – 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 is greater than the max size requirement for a DERA, 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)

<u>Simplified Example of Netted and Aggregated Modeling</u>
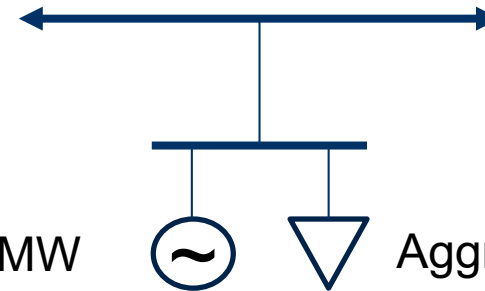
Netted (current method)   Aggregated (proposed method)
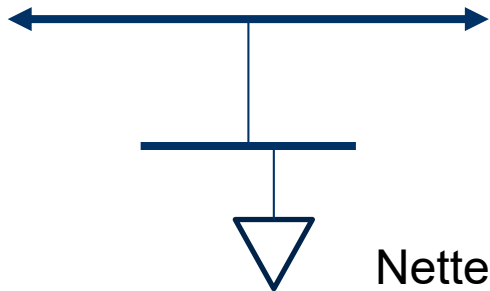
Transmission Network

Lowest Voltage PJM Modeled Bus

Netted Load = 30 MW Σ DERA = 5 MW   Aggregated Load = 35 MW

Proposed Data Requirements for Planning

- For each DER within a DER aggregation:
  - Address
  - Technology (solar, battery, landfill gas, wind, hybrid, etc.)
  - Maximum AC output (gross nameplate capability)
  - Interconnected distribution line identification
  - PJM Planning Model Bus ID 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

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.

- 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 (credit requirements will be detailed in a future meeting).

- 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.

- Likely will have parallels with the WMPA.

  – Notable exception: will be a *pro forma* agreement under the Tariff, so could in theory meet FPA 205(c) obligation via EQRs.

- Attestation that DERA is compliant with tariffs/operating procedures/rules of distribution utility and RERRA.

- 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 and opt-in requirements of Order Nos. 719 and 719-A still apply for Demand Response resources.

  – *Order 2222-A clarifies Order Nos. 719 and 719-A only apply to homogenous aggregations of Demand Response.*

- DR Opt-in/Opt-out process would apply to the following resources *participating in a homogenous aggregation*:

  – Demand Response (load curtailment) resources

  – Resources participating with load curtailment and FTM injections in PJM Markets (TBD)

- Order 2222 Opt-in process would apply to the following resources:

  – FTM generator, energy storage, and energy efficiency resources

  – All resources within a heterogeneous aggregation.

- DER aggregators will need to provide **resource weighting factors** (distribution factors in FERC Order) for the DERs participation in the DERA.

- Resource weighting factors will be calculated during the registration (via utility review) process based on the nameplate capacity of the resources in the aggregation.
  - Example: DER1 = 1MW, DER2 = 1MW; weighting would be DER1=0.5, DER2=0.5

- Further discussion on updating of weighting factors and the usage of these values are included after the example of locational requirements

- *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

- Each DER to be identified and mapped in the PJM network model

- Proposal: All DERs will be mapped individually in PJM network model
  - The location of each DER will be based on electrical impact and determined during the DERA registration process
  - Aggregator will submit location of DERs, EDC will verify and work with PJM for the proper mapping

Operations

- 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 define Capacity participation or Ancillary Service performance evaluations
  - *Capacity participation will allow aggregations up to the zone/sub-zonal LDA
  - *Ancillary Service performance evaluations will allow broader aggregations
    - Regulation: Performance Groups can be formed zonally
    - Reserves: Performance netting for Market Sellers within defined reserve zones.

*more details later in presentation

- Initial proposal: DER Aggregation not allowed beyond a single location ("nodal" from FERC Order)
  - Examples and discussion on following slides

Alternative Approach: A multi-location ("multi-nodal") model. This model would have increased inefficiencies in dispatch and LMP formation. However, this model would still model DERs nodally and restrict aggregations to utility footprints; this would be an improvement over a zonal aggregation model with respect to operational and pricing concerns.

Single Location Requirements

DER	(Utility Review) Primary transmission location	Aggregation Definition	(Utility Review) Additional data from EDCs for modeling
DER1	Node A	DERA 1	100% Node A
DER2	Node A	DERA 1	100% Node A
DER3	Node A	DERA 1	80% Node A, 20% Node B
DER4	Node A	DERA 1	70% Node A, 30% Node D
DER5	Node B	DERA 2	70% Node B, 30% Node A
DER6	Node C	DERA 3	100% Node C

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).

Operations

- Example will look at 4 DER resources with an aggregate capacity of 1MW
  - DER1 = 400kw, DER2 = 300kw, DER3 = 200kw, DER4 = 100kw

- Examples:
  - Nodally, aggregation of multiple DERs & aggregation of 1 *PJM Initial Proposal*
  - Multi-nodal, Aggregate pricing nodes will be developed based on the underlying DER nodes for the purpose of calculating LMP and dispatch
  - Zonal aggregation *Example for comparison purposes, not being proposed for Order 2222*
    - Map resources to zonal aggregate

- 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.

Nodal Aggregation Model

Locational Requirements

Enode-1
-DER1
-DER2
-DER3
-DER4

Pnode1
DERA1
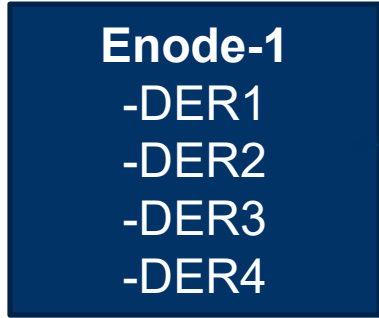
EDC/PJM determined all DERs mapped to same tranx node.

DER	Weight	Enode	dfax
1	0.4	1	-0.468
2	0.3	1	-0.468
3	0.2	1	-0.468
4	0.1	1	-0.468

- LMP = Energy LMP + sum of congestion LMP + loss LMP
  - Energy LMP = $25, Constraint shadow price = -500, Loss LMP = 0
- P1 LMP = $25+(-0.468 *-500) + 0
- P1 LMP = $259
- Dispatch of DERA= 1MW

Dispatch Engine will not take into account the weighting factors provided by the DERA

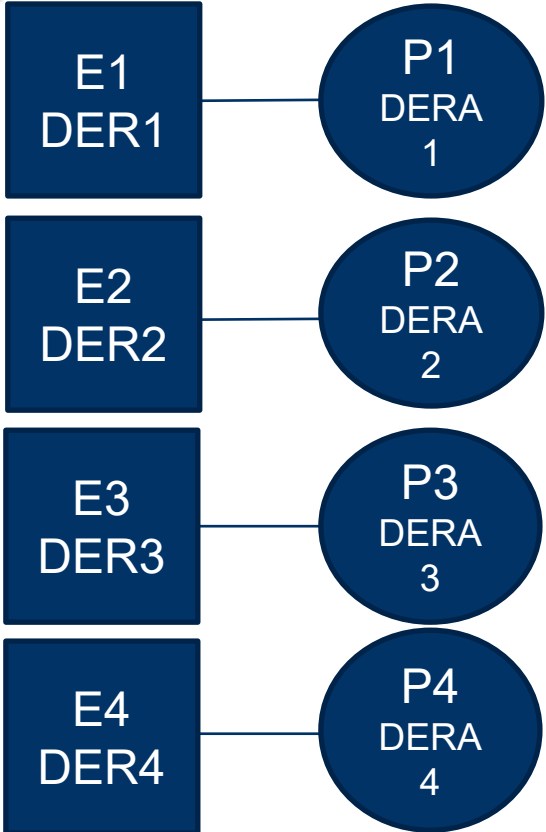May still need weighting factors on nodal aggregations
- Cost Offers
- Settlements (DR, ESR breakout)

DER	Weight	Enode	dfax
1 (400kw)	1	1	-0.468
2 (300kw)	1	2	0.093
3 (200kw)	1	3	-0.145
4 (100kw)	1	4	0.006

E1
DER1

P1
DERA
1

E2
DER2

P2
DERA
2

E3
DER3

P3
DERA
3

E4
DER4

P4
DERA
4

LMP = Energy LMP + sum of congestion LMP + loss LMP
    Energy LMP = $25, Constraint shadow price = -500, Loss LMP = 0
P1 LMP = $25+(-0.468 *-500)+0 = $259   Dispatch =400kw

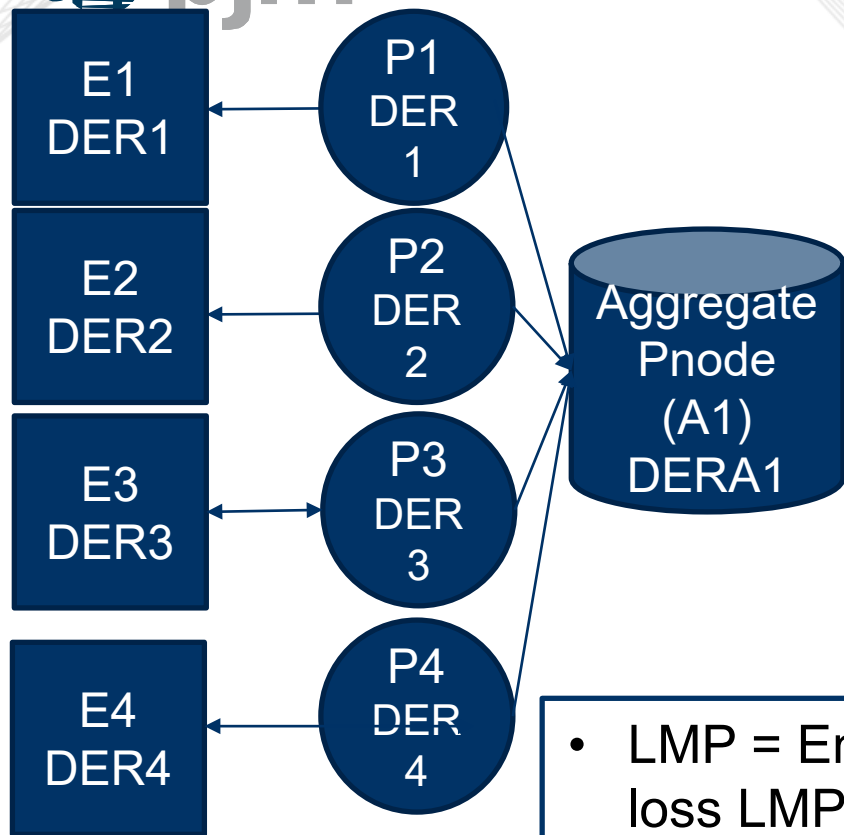P2 LMP = $25+(0.093 *-500)+0 = $-21.5   Dispatch = 0kw

P3 LMP = $25+(-0.145 *-500)+0 = $97.5   Dispatch = 200kw

P4 LMP = $25+(0.006 *-500)+0 = $22   Dispatch = 100kw

EDC/PJM determined all DERs mapped to different tranx node. In this case these DERs would not be allowed to be dispatched as 1 DERA, they need to be dispatched as different DERAs based on node.

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

- 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.

- 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

E1 DER1

E2 DER2

E3 DER3

E4 DER4

P1 DER 1

P2 DER 2

P3 DER 3

P4 DER 4

Aggregate Pnode (A1) DERA1

Operations

- DERAs will provide weighting factors for expected Energy on an hourly basis for Day Ahead.

  - Example: Hours 1-12 DER1=0.5, DER2=0.5, Hours 13-24 DER1=1, DER2=0.

- Open question on how accurate these values can be and if resources will operate to them in real-time

  - Visibility of DER operations will be valuable if accurately forecasted and provided for dispatch and pricing

Example has 1 DER at each Pnode in DERAs. Weighting factors for pricing each by Pnode.

- PJM is still reviewing the option of (1) updating the weighting factors in real-time and (2) setting expectations of following those weighting factors (applying penalties for not following weighting factors)

  – Complexities to having updated weighting factors, but increased visibility.

- Concerns around dynamic weighting factors

  – DERAs influence price and create false arbitrage opportunities by changing weighting factors in real time vs. day ahead

  – Are weighting factors able to be provided accurately to PJM from aggregators?

    - If weighting factors are provided and/or updated, can DERAs be held to operating as such?
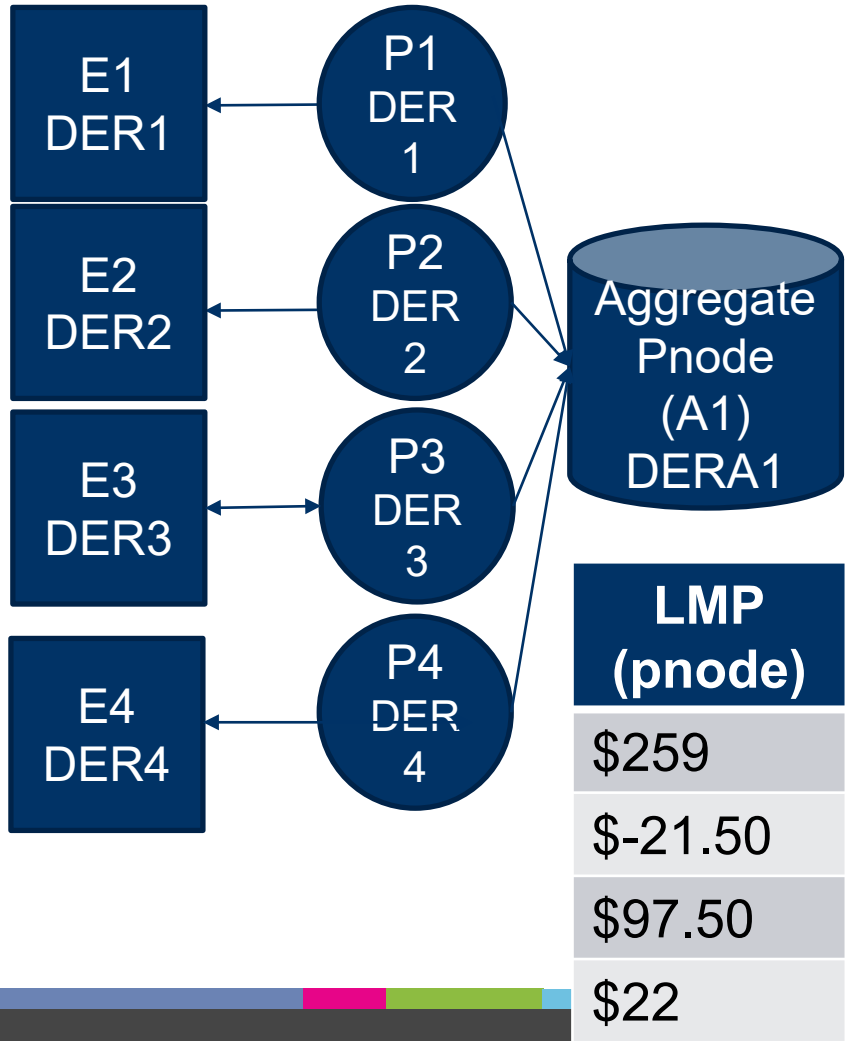
Day-Ahead	Real-Time
Weighting	Weighting
DER1 = 0.4	DER1 = 1
DER2 = 0.3	DER2 = 0
DER3 = 0.2	DER3 = 0
DER4 = 0.1	DER4 = 0
LMP = $118.85	LMP = $259

- Same MWs from the DERA, with different pricing dependent on weighting factors

- Example assumes same conditions in DA and RT

E1
DER1

E2
DER2

E3
DER3

E4
DER4

Zonal Agg.
Pnode (Z1)
DERA1

Zonal Aggregate dfax **= 0.028**
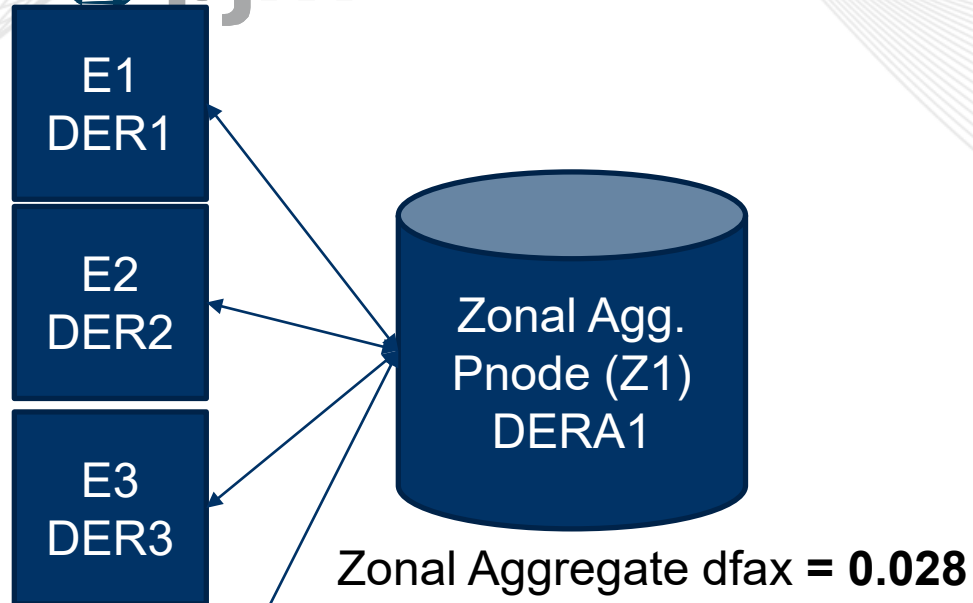
DER	Weight	Enode	Zonal dfax
1	0.4	1	0.028
2	0.3	2	0.028
3	0.2	3	0.028
4	0.1	4	0.028

- LMP = Energy LMP + sum of congestion LMP + loss LMP
- Zonal Aggregate LMP = $25+ (0.028*-500) + 0
- Zonal Aggregate LMP = $25 + ($-14) + 0
- Zonal Aggregate LMP = $11
- Dispatch of Zonal Aggregate would be 0MW

- Zonal aggregation not being explored as part of Order 2222 due to the inaccurate dispatch in comparison to location of resources within potential aggregation.
  - Dispatch at the zonal level is a lower-help, even though in aggregate the resources would be a raise-help.
  - DERA is dispatched to 0MW (ecomin)
- Zonal aggregation also minimizes visibility and dispatch of resources for Operations.

If DERA was mapped nodally

- P1 LMP = $25+(-0.468 *-500)+0 = $259
  - Dispatch =400kw
- P2 LMP = $25+(0.093 *-500)+0 = $-21.5
  - Dispatch = 0kw
- P3 LMP = $25+(-0.145 *-500)+0 = $97.5
  - Dispatch = 200kw
- P4 LMP = $25+(0.006 *-500)+0 = $22
  - Dispatch = 100kw

If DERA was mapped to aggregate node (multi-nodal)

- A1 LMP = $25+(-0.1877 *-500) + 0 = $118.85
  - Dispatch of Aggregate Unit (A1) = 1MW

If DERA was mapped to Zonal Aggregate

- Zonal Aggregate LMP = $25+ (0.028*-500) + 0 = $11
  - Dispatch of Zonal Aggregate = 0MW

- DERAs not allowed beyond a single location (nodal) will provide consistent dispatch and pricing with PJM constraint control and nodal price formation
- DERAs that are aggregated across a zone (multi-nodal) can provide appropriate dispatch for aggregation but introduces inefficiencies for underlying DERS
  - Brings up concerns on weighting factor accuracy and price arbitrage opportunities
- DERAs that are aggregated at the zonal aggregate would not (in many cases) align to desired dispatch or pricing

- What DERAs have to provide telemetry to PJM?
  - Capacity & Energy Participation
  - Ancillary Service Participation – faster scan rates

Alternative Approach:
(1) Further evaluate if telemetry is needed for all capacity participation (possibly dependent on technology and size of DERA)

Telemetry discussion is focused on real-time data to be provided.
After the fact meter data will also be needed and discussed later in this presentation

- Aggregator will send telemetry values for **the DERA** to PJM
  - MW telemetry values sent in all cases
  - No MVAR data required to be sent to PJM
  - Transmit through Internet-based SCADA (Jetstream)
    - ICCP links to PJM also available
- Aggregators may be expected to have individual DER telemetry data available
- Scan Rate frequency determined by chosen market participation
  - Regulation: 2 second (Reg-D), 10 second (Reg-A)
  - Energy: 10 second

Alternative Approach:
(1) Scan Rate requirement for Energy would be 1 minute.

- Outage information needs to be provided to PJM at the individual DER level for capacity resources

- Cyber Security
  - Jetstream with aggregator
  - DER communication to aggregator or to utility also should have cyber security protocols in place

- Level of market participation will dictate data requirements

- DERs can participate under existing models or the proposed new "DERA" model.

- 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 new DERA model
  - DERs can participate as an aggregation (one or more DERs)
  - Can be homogenous (include one technology type) or heterogeneous (include multiple technology type)

- The DER aggregator of the DERA is the market participant in PJM, not the underlying DERs.

- Market Products that will be available to DERA participants: Capacity, Energy, Ancillary Services (Regulation & Sync Reserves).

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Market Design

Managing Aggregations

DER	(Utility Review) Primary transmission location	Aggregations for dispatch (locational reqts.)	Aggregations for Capacity (DERA CP Resource)*	Aggregations for Ancillary 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 Reserve Zone requirements for Reserves

Registration/ Utility Review

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

Customers

DR	Nominated Value — DER 1
Mass Market Residential Home: 1 2 3	TBD — DER 2
EV	Nominated Value — DER 3
PV & ESR	ELCC — DER 4

Weighting Factors: all 0.25

DERA 1

Gen	Capacity — DER 5	0.50
ESR	ELCC — DER 6	0.25
ESR	DER 7	

DERA 2

| EE | DER 8 — PI M&V |

DERA CP Resource
(Capacity Exchange)
Capacity Commitment
(determined by how DERA clears in auction)
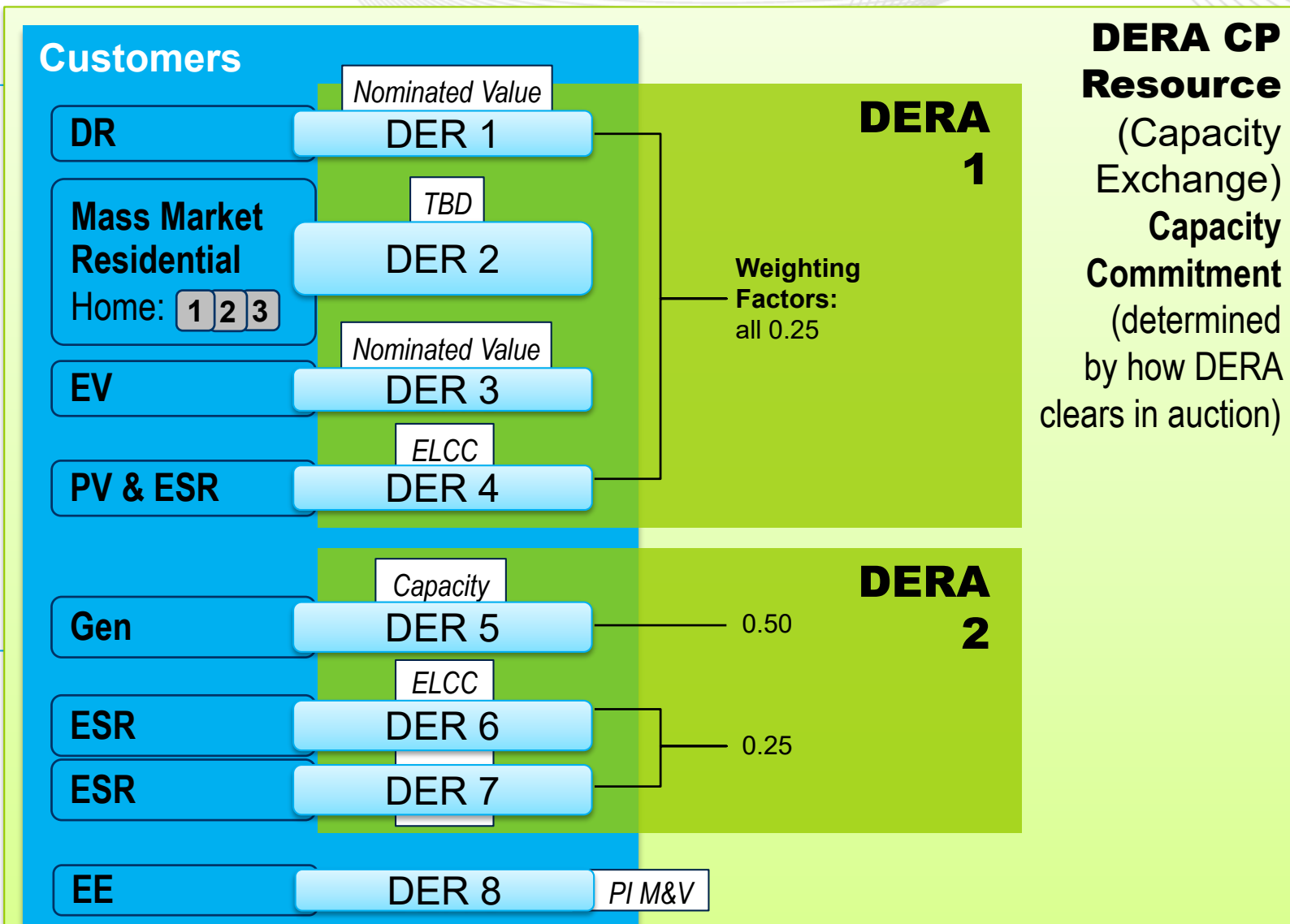
○ **CP Resource**
- Aggregation of many DERs across LDA
- Min = 100 kW
- Max = No max requirements

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

○ *Capacity Value*

Capacity

– Homogenous and Heterogeneous DERA CP Resources will be defined within a zone/sub-zonal LDAs

  • Capacity values, MOPR values, and Performance will be evaluated at DER level (allows for consistent rules with existing technology)

– There will not be a Must Offer Requirement in Capacity Market for DERA CP Resources

– Non-Performance Assessment for DERAs

  • Existing penalty and bonus rules will apply to DERAs

  • Netting of performance will be available for DERs within the DERA CP Resource

    – No netting of performance across DERA CP Resources in a market seller account

  • Excusals for outages (assuming an approved outage during PAI)

  • No dispatch excusal if resources are self-committing or dispatched by utility for reliability

Capacity Participation

- **Planned DER** will be able to participate in the Capacity Auction under certain circumstances.

  – Planned DER <25kw or of the Demand Response type 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

  – DER >25kW, will also need to submit paperwork identified the Interconnection has been started with the applicable utility.

Alternative Approach:
(1) Do not allow Planned DER into Capacity Auction; require all DER in a DERA to have a signed IA prior to offering in BRA

Capacity Participation

- **Emergency DER** will not be able 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

Alternative Approach:
(1) Allow Emergency DER to participate in Capacity under DERA
(2) Allow Emergency DER to participate in Capacity under DERA with a defined limit

Energy

- Option 1: DERA will participate in Energy under a 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 not be required to submit cost based offers.

  - DERAs will not be eligible for LOC or make whole.

  - DERAs with underlying storage will have access to participating under the ESR model to reflect charging

Alternative Approach: A dispatch model. This model would have trade offs with additional requirements in the design (example: cost based offers, additionally telemetry)

Market Design

Energy

- Option 2: DERA will participate in Energy under a no-commitment model, PJM dispatch available
  - 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 cost based offers and construct FCPs.
  - DERAs will be eligible for LOC or make whole if manually dispatched.

Alternative Approach: A dispatch model. This model would have trade offs with additional requirements in the design (example: cost based offers, additionally telemetry)

Market Design

Cost Based Offers

- Cost based offers are necessary for PJM Energy market to manage market power

  - DERAs have the ability to have market power, and cost based offers would be required for DERAs to be dispatched by PJM

- Fuel Cost Policies will also be required of all DERAs with a non-zero cost offer

- Cost based offers will be complex to develop and verify for DERAs, depending on aggregation.

> PJM welcomes proposals from stakeholders on how to accurately and transparently calculate cost offers.

Ancillary Services

- DER aggregations (DERA) will be allowed to participate in the following Ancillary Service markets
  - (1) regulation
  - (2) synchronized reserves
- DERAs will not be prohibited to offer resources into Black Start RFPs for consideration on Black Start Service
  - DERAs would be evaluated on a case-by-case basis based on RFP response

Ancillary Services - Reserves

- DERAs will follow the same business rules as detailed in Manual 11 Section 4 for reserves.
  - DERAs are eligible to provide synchronized reserves.
  - DERAs are ineligible to provide non-synchronized reserves
    - DERAs will be self-committing into PJM's Market and therefore will be considered synchronized.
  - DERAs will need to contained within a predefined reserve zone or subzone
  - 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

- DERA will be able to aggregate performance during a spin event
  - For performance shortfall assessment during a spin event, DER aggregators that own multiple DERAs assigned or self-scheduled to provide reserve are permitted to demonstrate aggregate response to allow resources with greater response to offset any resources that respond less than there assignment. This is consistent with existing business rules for reserve performance, as documented in PJM Manual 28.

Ancillary Services - Reserves

- Reserve offer requirements for DERA are still being evaluated

Alternative Approaches:

(1) DERAs, by default, will not considered for reserves, but may request an exception to participate.

(2) DERAs will be required to offer reserves, dependent on existing requirements for underlying resource types (ex. A DERA of Solar would not be considered for reserves, A DERA of generation would be considered for reserves)

(3) DERAs will be required to offer reserves, independent of underlying resources in aggregation (possible resource exception)

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Market Design

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.

- *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)*

Sizing Requirements for DERs (individual resources)

- Setting a maximum size requirement on individual DERs participating in an aggregation, will allow PJM to maintain the correct level of study and visibility of resources to maintain reliability. Larger resources, and resources injecting on to the BES will need to be independently modelled, metered, and operated in PJM's system.

- No minimum size requirements will be defined.

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Market Design

Sizing Requirements for DERs (individual resources)

- DERs > 5MW will not be eligible to participate in a DERA.
  - DERs <= 5MW will be eligible to participate in a DERA, given they satisfy the other DERA participation requirements.

Alternative Approaches:

(1) DERs >5MW may participate in a DERA, given they satisfy the other DERA participation requirements, but would be subject to providing individual telemetry/metering on the resource and/or participating as an aggregation of 1.

(2) Requirement for DERs >5MW, injecting past the customer meter to be ineligible to participate in DERA. DERs with sole activity behind the meter would not be subject to a maximum size requirement.

Market Design

Sizing Requirements for DERA (aggregation resource)

- Minimum size requirements for DERA will be 100kw for Market participation

- Assuming a nodal aggregation, no maximum size requirements for DERAs.

  – Implementing a multi-nodal approach would require maximum size requirements to manage constraint control and pricing of the aggregate

  – Initial proposal: DERAs across multiple nodes would be 1MW or less

- Meter data is required to be provided by the aggregator for the DERA next business day after operating day ([submission-deadlines](#))

  – Meter data will be required for the aggregation

  – Meter data will be required from the individual DER resources in some cases (Demand Response, Energy Storage, DERS participating in Capacity, Heterogeneous aggregations).

- Meter data will need to be hourly granularity (or less)

Alternative Approach:
(1) DER Aggregator to provide data at individual DER level in all cases and PJM would provide the aggregate calculation for the DERA.

- Existing Metering Requirements

- Manual 14D Section 4.2.2: Metering Plan and 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."*

- 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 to PJM by the PowerMeter deadline (1 business day after the operating day)

  – Be mapped at a pricing node (instead of the zonal residual aggregate)

- DER units and DERA 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.

- DER units and 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 any reduction above their expected amount carved out and settled as real-time load response

- With DER and DERA being modeled as no-commitment units, DER and DERA units 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.

- DER and DERA resources can receive Operating Reserve Deviation Charges. Currently PJM is evaluating whether DERA will be evaluated for deviations at the aggregate or nodal level.

- DERAs settlements will be calculated at the nodal level.

  – Each unit will have a charge calculated using the node at which they are modeled

  – PJM will sum all of these charges to the aggregated level

Settlements

- FERC Order 2222 states that PJM will need to still follow FERC Order 745 rules when settling DR in a DERA
  – Any DR resources in a DERA will have their settlements calculated following demand response business rules
  – PJM is evaluating whether the Net Benefits Test will be performed at the nodal price or the weighted average LMP of the aggregate
- DR Resources within a DERA will only be eligible to receive operating reserve make-whole credits if the aggregate is eligible to receive operating reserve make-whole credits.

Settlements

Customer ID	Unit ID	Day-ahead MWs	Day-ahead LMP ($/MW)	Day-ahead Spot Market Charges ($)
CA123	Unit456	10	$100	$-1000

Customer ID	Unit ID	Real-time Metered Load	Balancing MWs	Real-time LMP ($/MW)	Real-time Spot Market Charges ($)
CA123	Unit456	9	1	$150	$150

Settlements

Node	Unit	LMP ($/MWh)	Unit MWs	Expected MWs	Spot Market Charges	
					Calculated Nodally ($)	Calculated at the Aggregate ($)
Node 1						
	Unit 1	$ 259.00	1	1	$ (259.00)	$ (118.85)
	Unit 2	$ 259.00	1	1	$ (259.00)	$ (118.85)
	Unit 3	$ 259.00	2	2	$ (518.00)	$ (237.70)
Node 2						
	Unit 1	$ (21.50)	2	2	$ 43.00	$ (237.70)
	Unit 2	$ (21.50)	1	1	$ 21.50	$ (118.85)
Node 3						
	Unit 1	$ 97.50	1	1	$ (97.50)	$ (118.85)
	Unit 2	$ 97.50	0.5	0.5	$ (48.75)	$ (59.43)
	Unit 3	$ 97.50	0.5	0.5	$ (48.75)	$ (59.43)
Node 4						
	Unit 1	$ 22.00	0.7	0.7	$ (15.40)	$ (83.20)
	Unit 2	$ 22.00	0.3	0.3	$ (6.60)	$ (35.66)
Totals			10	10	$ (1,188.50)	$ (1,188.50)

Node	Unit	LMP ($/MWh)	Unit MWs	Expected MWs	Spot Market Charges		Is Deviating
					Calculated Nodally ($)	Calculated at the Aggregate ($)	
Node 1							
	Unit 1	$ 259.00	4	1	$ (1,036.00)	$ (475.40)	Y
	Unit 2	$ 259.00	0	1	$ -	$ -	Y
	Unit 3	$ 259.00	0	2	$ -	$ -	Y
Node 2							
	Unit 1	$ (21.50)	2	2	$ 43.00	$ (237.70)	N
	Unit 2	$ (21.50)	1.1	1	$ 23.65	$ (130.74)	N
Node 3							
	Unit 1	$ 97.50	1	1	$ (97.50)	$ (118.85)	N
	Unit 2	$ 97.50	0.5	0.5	$ (48.75)	$ (59.43)	N
	Unit 3	$ 97.50	0.5	0.5	$ (48.75)	$ (59.43)	N
Node 4							
	Unit 1	$ 22.00	0.7	0.7	$ (15.40)	$ (83.20)	N
	Unit 2	$ 22.00	0.3	0.3	$ (6.60)	$ (35.66)	N
Totals			10.1	10	$ (1,186.35)	$ (1,200.39)	N

- **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.

  – PJM is still evaluating this specific scenario for wholesale participation; potential opportunity to participate in Ancillary Service and Capacity markets

  – These resources would not be paid for Energy in PJM Markets

    • Double Counting (cannot net load and be paid in wholesale market) and not aligned with current PJM BTMG business rules.

- **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.

- Energy Accounting needs to stay balanced. It will be important to demonstrate likely use cases and the necessary meter data required for settlements.

  – Question to answer in use case development : What metering is necessary for retail billing adjustments

- PJM would like to start working use case development in the DIRS in May/June timeframe

> PJM welcomes proposals from stakeholders on how different DERA use cases can participate in wholesale markets and be metered.

- Use Case 1: A resource operating behind a meter that also injects past the meter
  - Status Quo capacity
    - Generation = net injection determines capacity value
    - DR = PLC determines capacity value, only participates with load reduction
  - Option 1: Sub-meter resource
    - All wholesale activity, no retail activity from resource
    - Utilities would need to reconstitute load
  - Option 2: Allow both "demand response" and "gen/injection" participation
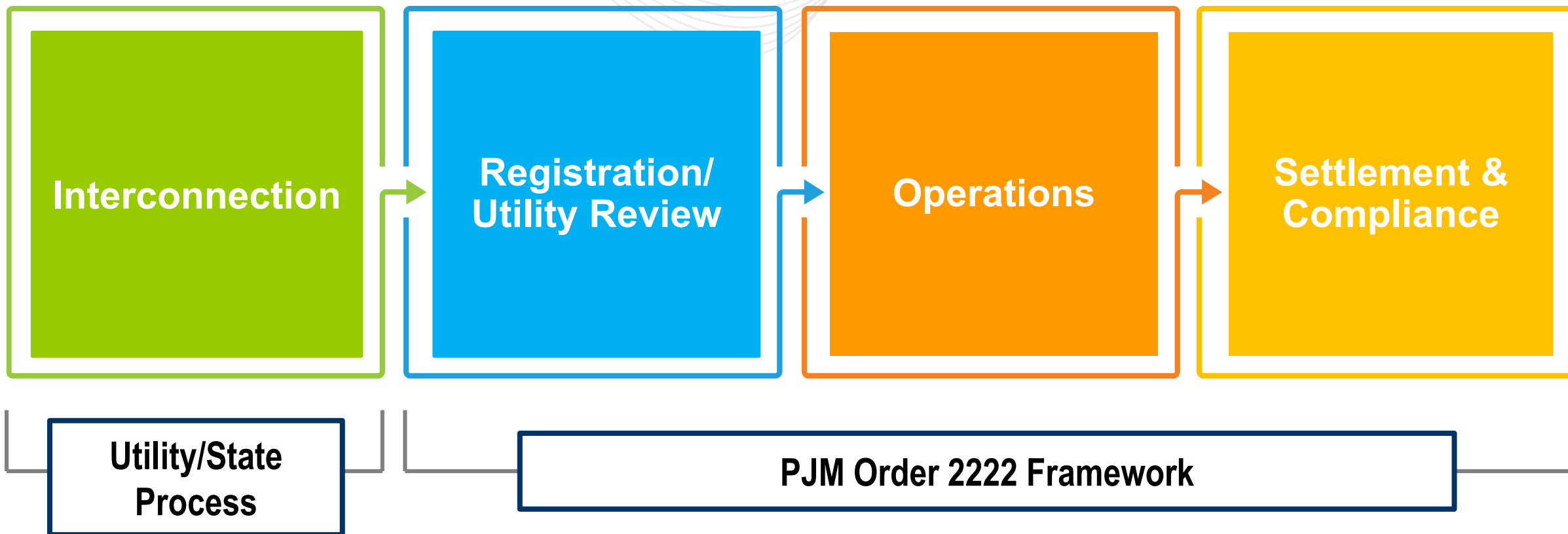   - Need to verify metering and double counting with the option

PJM welcomes proposals from stakeholders on how different DERA use cases can participate in wholesale markets and be metered.

Settlements

- Other use cases to be worked in the DIRS
  - BTM Solar
  - BTM Solar + Storage
  - EVs (V2G)
  - Net metering

PJM welcomes additional use cases to be worked.

Settlements

Interconnection → Registration/ Utility Review → Operations → Settlement & Compliance

Utility/State Process

PJM Order 2222 Framework

Coordination

- **Interconnection**
- Registration/Utility Review
- Operations
- Settlement & Compliance

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

- Interconnection
- **Registration/Utility Review**
- Operations
- Settlement & Compliance

Coordination

- Electric Distributor definition:
  - a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

- Review and approve DERA participation in the wholesale market
  - Ensure participation does not create safety and reliability issues on the distribution system
  - Participation complies with RERRA "small" EDC process
    - Participation is only allowed if there is an effective order, ordinance or resolution
  - Assist with the review and collection of certain data
  - Settlements

- Registrations submitted by DER Service Provider (DERSP) after resource goes through utility interconnection process
- EDC has 60 days to review and approve the registration
  - If the registration is denied and DERSP resubmits, then EDC has 15 business days to review
    - Denied registrations must indicate specific reason and data field for denial
  - If EDC denies and DERSP disputes then there is 60 days to resolve between PJM, EDC and DERSP.
  - Registration outcome if no action from EDC before deadline
    - Small EDC will auto deny
    - Large EDC will auto approve
- PJM has 10 business days for final registration approval
  - Auto-confirm unless EDC has reliability concerns

Coordination

Data	Notes	DERSP	EDC	PJM
Registration Start/End date		Submits	review	review
Registration Status		Submits	review	review
Transmission Zone		Submits	approve/deny	review
EDC		Submits	approve/deny	review
EDC account information	Multiple DERs may be on one Registration	Submits	approve/deny	review
Physical address for DER		Submits	approve/deny	review
EDC Interval Meter (if applicable)		Submits	approve/deny	review
PJM Telemetry setup		Submits	review	approve/deny
RERRA Evidence	Small EDC reference to RERRA that allows participation	Submits	approve/deny	review
Energy Pricing Point - pnode	Expect that PJM will create default based on zip code and EDC will review and update with focus on larger larger DER	review	submits/updates - approve/deny	submits
Market	DA/RT Energy, SR, Regulation	Submits	review	approve/deny
Expected participation hours		Submits	review	review
Max Load (kW)	Max hourly load over prior 12 months	Submits	approve/deny	review
Max Injection (kW)	Max injection amount based on interconnection process	Submits	approve/deny	review
Max Market Eligibility	Maximum amount that will be offered in the market	Submits	review	review

Expect to leverage functionality similar to DR registrations in DR Hub

Data	Notes	DERSP	EDC	PJM
Technology Type	1 record for each type that will participate: Solar, Battery, CT, DR	Submits	review	review
Type details	1 record for each type: additional details	Submits	review	review
Size	Nameplate rating	Submits	review	review
Utility Interconnection ID	Reference to approved Utility interconnection	Submits	approve/deny	review
Retail Agreements	NEM, PURPA, etc.	Submits	approve/deny	review
Peak Load Contribution (PLC) (if applicable)		Submits	approve/deny	review
Loss Factor (if applicable)		Submits	approve/deny	review
Inverter Type		Submits	review	review
Installation Date		Submits	review	review
Ride through capability enabled	Y/N	Submits	review	review
Voltage control enabled	Y/N	Submits	review	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	review	submits	approve/deny

Expect to leverage functionality similar to DR registrations (DR Hub)

Coordination

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

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

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

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

Will only participate in the Regulation market

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

Registration will indicate market eligibility

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.

EDC visibility for injection reason

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

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

Registration									Resource/Location					EDC Interconnection Number						
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	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
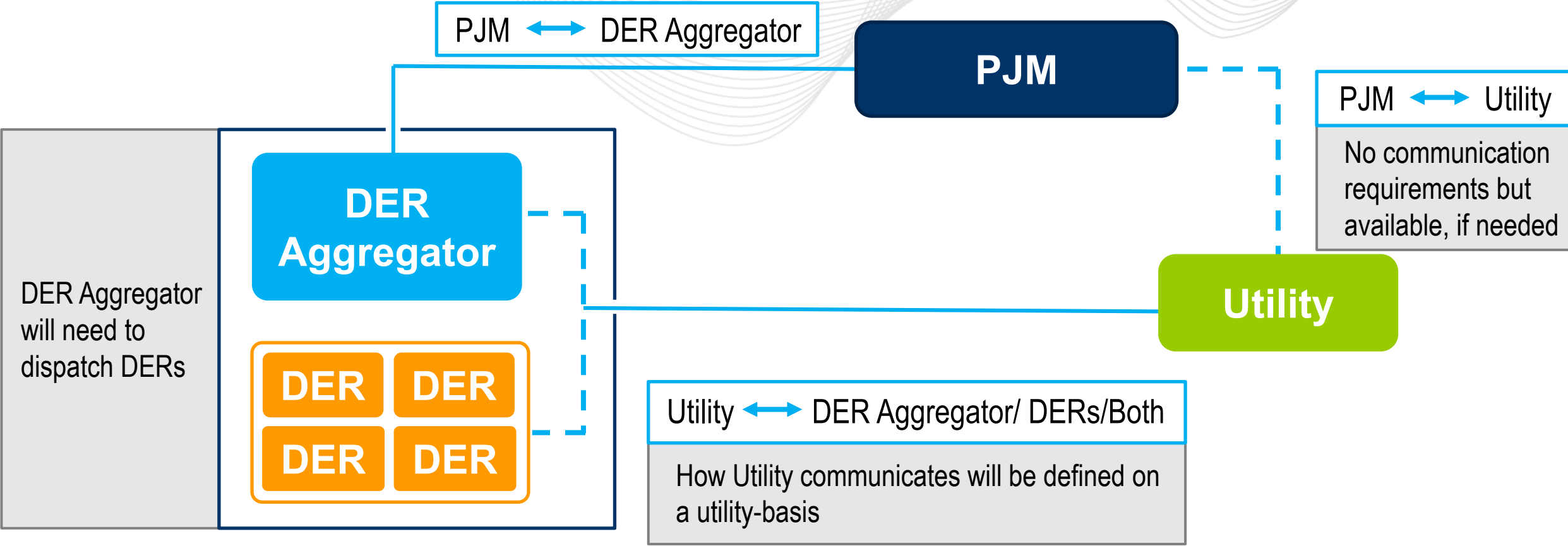
Only battery participates in wholesale regulation market

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

Coordination

- Process will need to be defined around what parts of the utility review are needed when an aggregator modifies the list of resources.
  - An abbreviated process (in most cases) to the full utility review

- Likely two different processes will be defined
  - Adding a resource to a DERA
  - Removing a resource from a DERA
- Registration aggregation (multiple resources on one registration) vs Dispatch Group (multiple registrations that are dispatched together)

- Interconnection

- Registration/Utility Review

- Operations

- Settlement & Compliance

DER Aggregator will need to dispatch DERs

PJM ⟷ DER Aggregator

PJM

DER Aggregator

DER DER
DER DER

PJM ⟷ Utility

No communication requirements but available, if needed

Utility

Utility ⟷ DER Aggregator/ DERs/Both

How Utility communicates will be defined on a utility-basis

⟷ Communication ▬▬ Required Communication ▬ ▬ Open Communication

Prior to Day Ahead Run
11:00

Utility
Notify Aggregator of any Ops Limitations

Aggregator
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

Utility
Receives DA Schedule (TBD)

Aggregator
Receives DA Schedule

Re-Bid and Intraday
14:15

Aggregator
Provide updates to allowable parameters to PJM

PJM
Receives parameters, dispatches based on updated parameters, and communicates response

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Coordination

Status Quo

Aggregator
Responds to dispatch and sends telemetry/will update bid parameters according to utility override

PJM
Dispatches Aggregation according to transmission conditions and BES constraints

Distribution Override

Utility
Notifies Aggregator of any overrides

Aggregator
Responds to dispatch and sends telemetry, will update bid parameters according to override

- PJM communicates primarily with aggregator throughout the process
- PJM wants EDCs to be empowered to address issues on the distribution system as quickly as possible

- Interconnection

- Registration/Utility Review

- Operations

- Settlement & Compliance

- PJM will need to define communication and data requirements to ensure proper settlements addressing both retail and wholesale billing
  - Will need to continue discussion at EDC coordination workshops and DIRS to identify use cases and needs.

Coordination

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