
PJM-EDC WORKSHOP MEETING

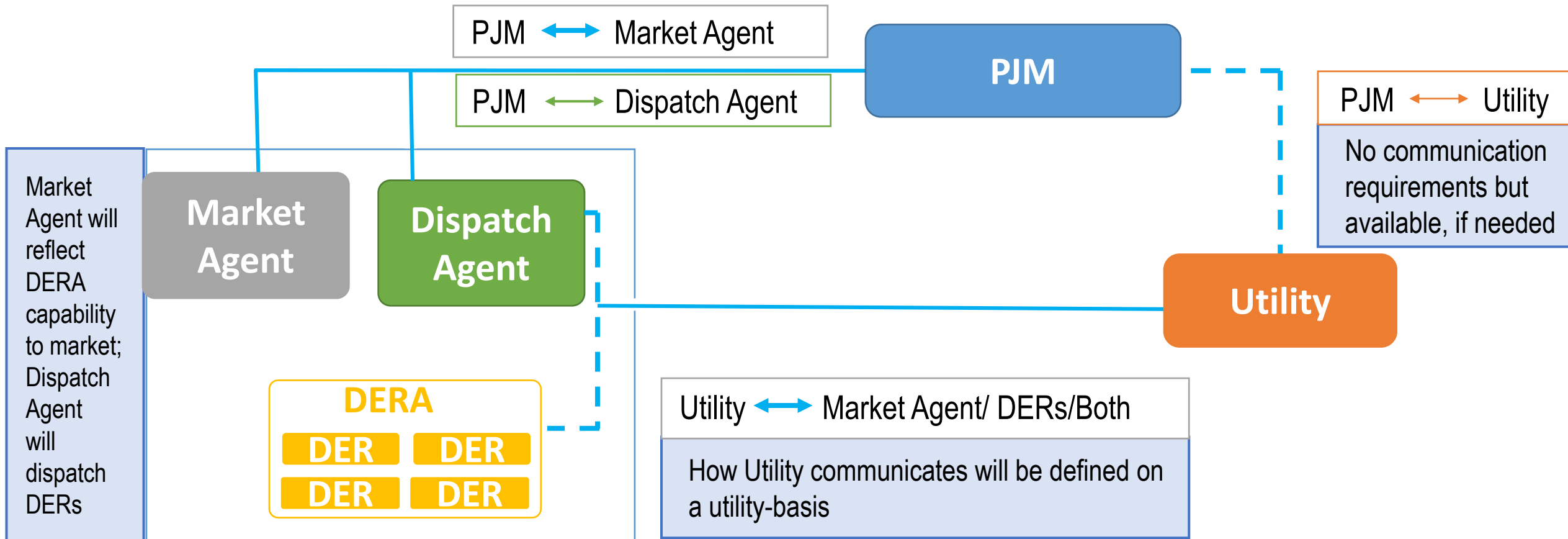
6/14/21

JOINT EDC CORE PRINCIPLE

It is required that EDCs **maintain their current role as distribution operators** in order to provide adequate levels of **safety, security, power quality**, and **reliability** of the power grid for **all** its customers. FERC Order No. 2222 does not change the role of the EDC in this capacity and no standards or processes developed in support of the FERC Order should seek to amend or adjust this role.

DER DISPATCHING MODEL

OPERATIONS COORDINATION: CURRENT PROPOSAL



Market Agent will reflect DERA capability to market; Dispatch Agent will dispatch DERs



Utility ↔ Market Agent/ DERs/Both

How Utility communicates will be defined on a utility-basis

PJM ↔ Utility

No communication requirements but available, if needed

Market Agent and Dispatch Agent could be DER Aggregator, Utility or 3rd party, designated by DER Aggregator in registration process.



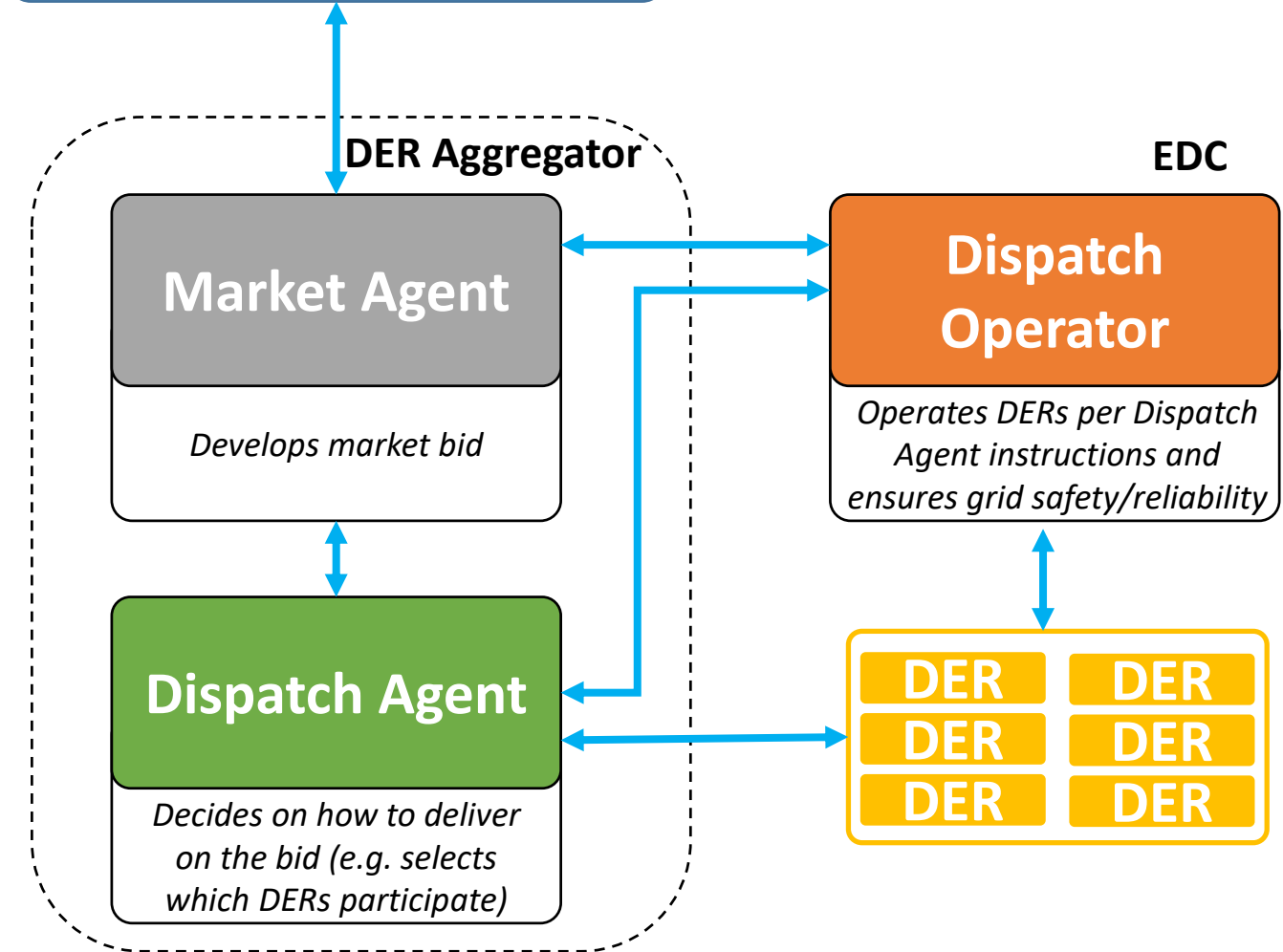
Coordination

SUMMARY

- Aggregators are not like normal generation currently seen on PJM's system today. They have a direct and complicated impact on reliability of the distribution grid due to their locational diversity.
 - Aggregators can't be treated like demand response as their active source injections.
 - A simplified version of the operations model that gives flexibility to EDCs, and Aggregators.
 - Aggregators can still be the Market Agent and the Dispatch Agent working with PJM on the market bid and selecting which DERs to participate in the bid.
 - The EDCs playing the role of the Dispatch Operator does not interfere with the Aggregators role. It is necessary to maintain the reliability of the grid which includes being able to override real time in case there is an identified constraint on the grid.
-

OPERATIONS COORDINATION: PROPOSED MODEL

RTO – BES & Wholesale Market Operator



Market Agent and Dispatch Agent:
DER aggregator or a designee

Dispatch Operator:
EDC or a designee

Utility ↔ Market Agent/DERs/Both

How Utility communicates will be defined on a utility-basis

Market Agent ↔ Dispatch Operator

Local Territory DER Capacity

Market Agent ↔ RTO

Wholesale/Aggregate DER Capacity

TELEMETRY MODEL

TELEMETRY MODEL



- 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.

Discussion Item

- Proposed strawman telemetry slides indicate that only a DERA will own and operate the telemetry system and data.

Concerns

- Other non-market telemetry needs including autonomous and active management for DER's (i.e. volt / var capabilities) are required by EDC's.
- Some EDC's already have customer DER telemetry installed for DER management that can be leveraged for telemetry for PJM market use. The current proposed model would have a redundant telemetry system installed in these situations.

Thoughts

- Telemetry models should involve a multi-model approach to avoid redundant telemetry systems at DER locations.
- If a DERA is the telemetry owner, EDC's may require capabilities to modify, through telemetry, a DER locations active and autonomous modes that will help to prevent constant utility overrides.

DERs: MULTIPLE FUNCTIONALITY CONSIDERATIONS



** Only functionality covered under FERC 2222 Order.

Market Functionality**

- A DER can active management commands that support FERC 2222 market dispatching (Active Power Output Setpoint, Remote On/Off) via a communication port on the inverter that is reserved for EDC use per the IEEE 1547.2018.

Power Quality Functionality

- A DER can receive autonomous settings that support locational power quality (volt/var curve, volt/watt) via a communication port on the inverter that is reserved for EDC use per the IEEE 1547.2018.
- A DER can receive active management commands that support system power quality (PF Setpoint, KVAR Setpoint) via a communication port on the inverter that is reserved for EDC use per the IEEE 1547.2018.

Reliability Functionality

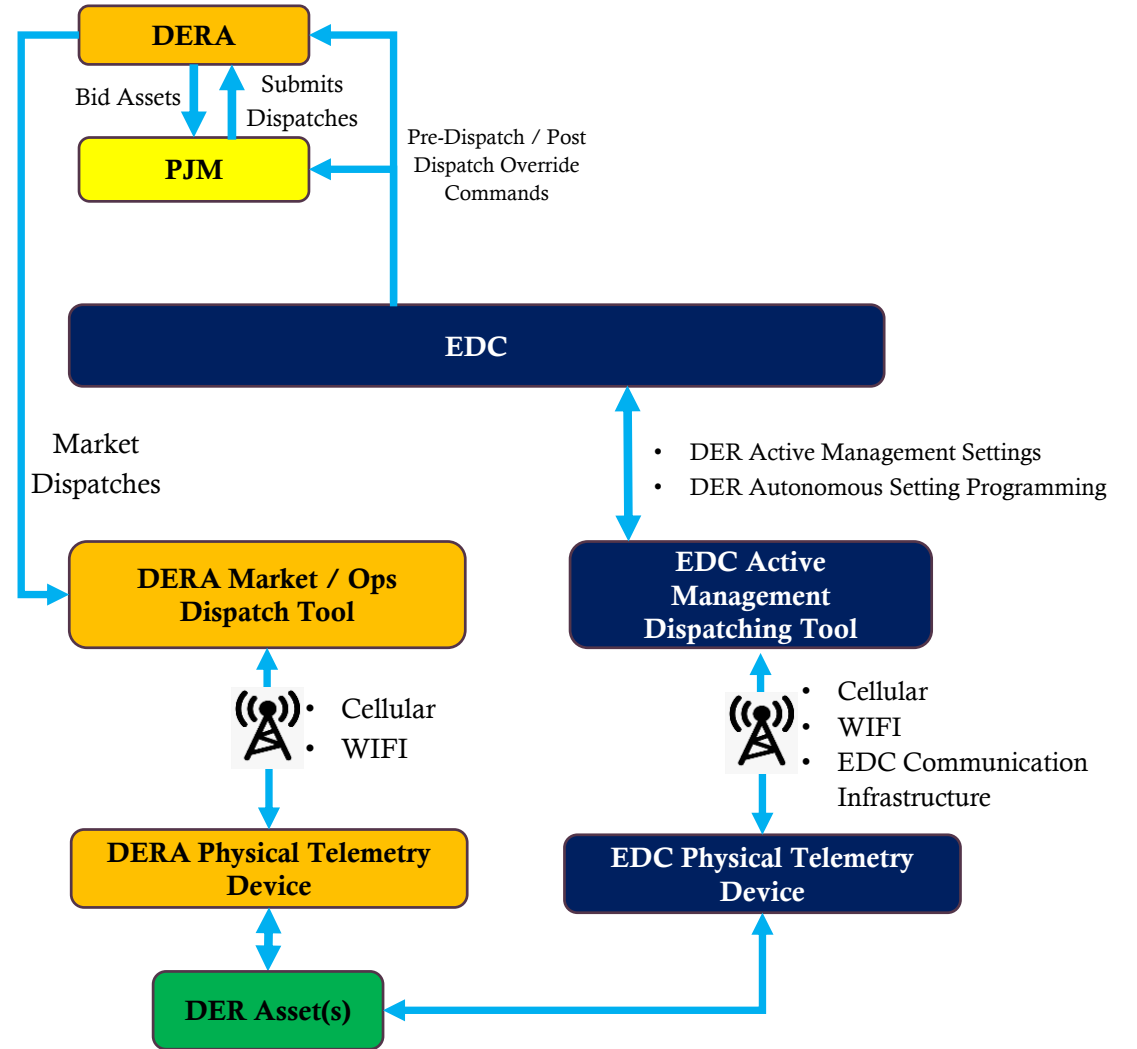
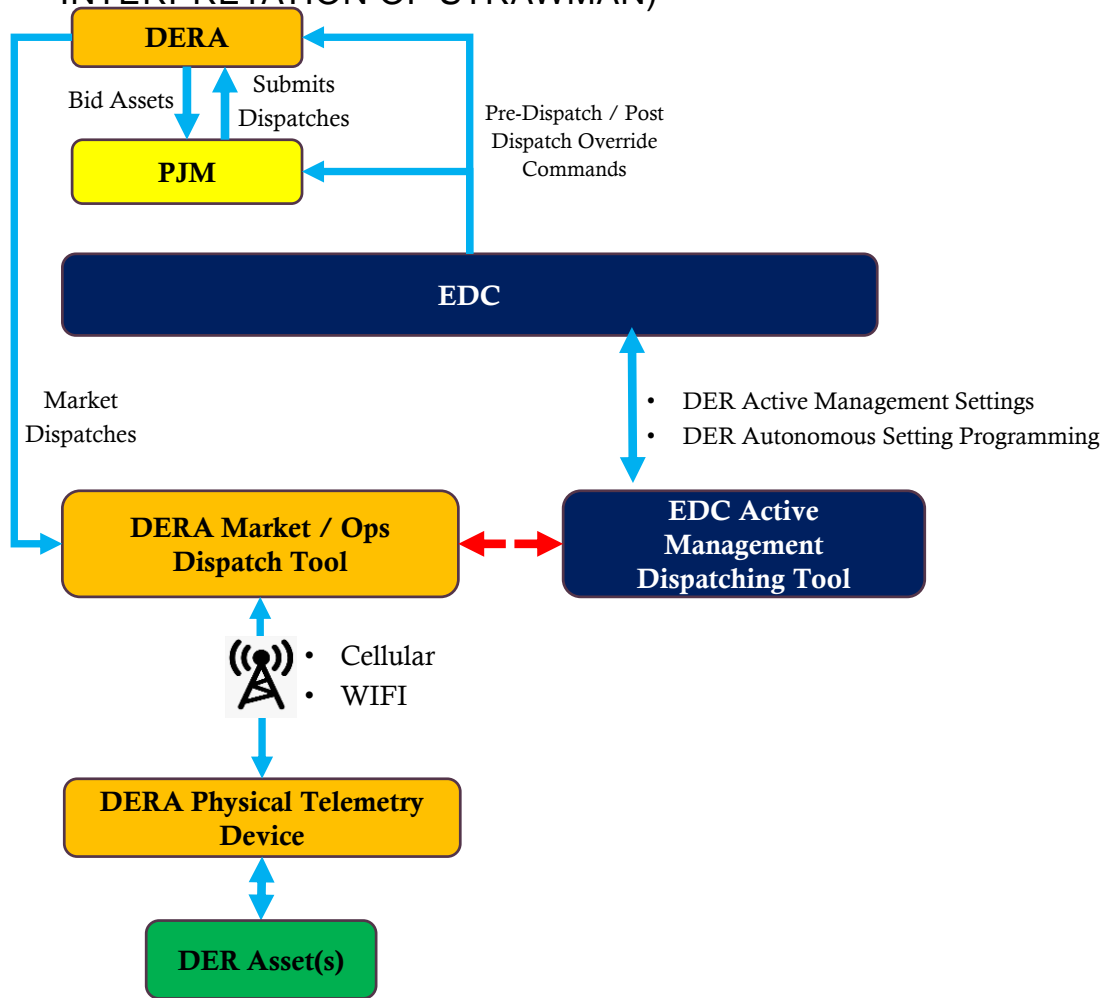
- A DER can receive autonomous settings that support system stability (voltage ride through, frequency ride through) via a communication port on the inverter that is reserved for EDC use per the IEEE 1547.2018.

Safety Functionality

- A DER can receive active management commands that support safety related tasks (remote on/off) via a communication port on the inverter that is reserved for EDC use per the IEEE 1547.2018.

TELEMETRY MODEL: CURRENT APPROACH (GRAPHICAL

INTERPRETATION OF STRAWMAN)



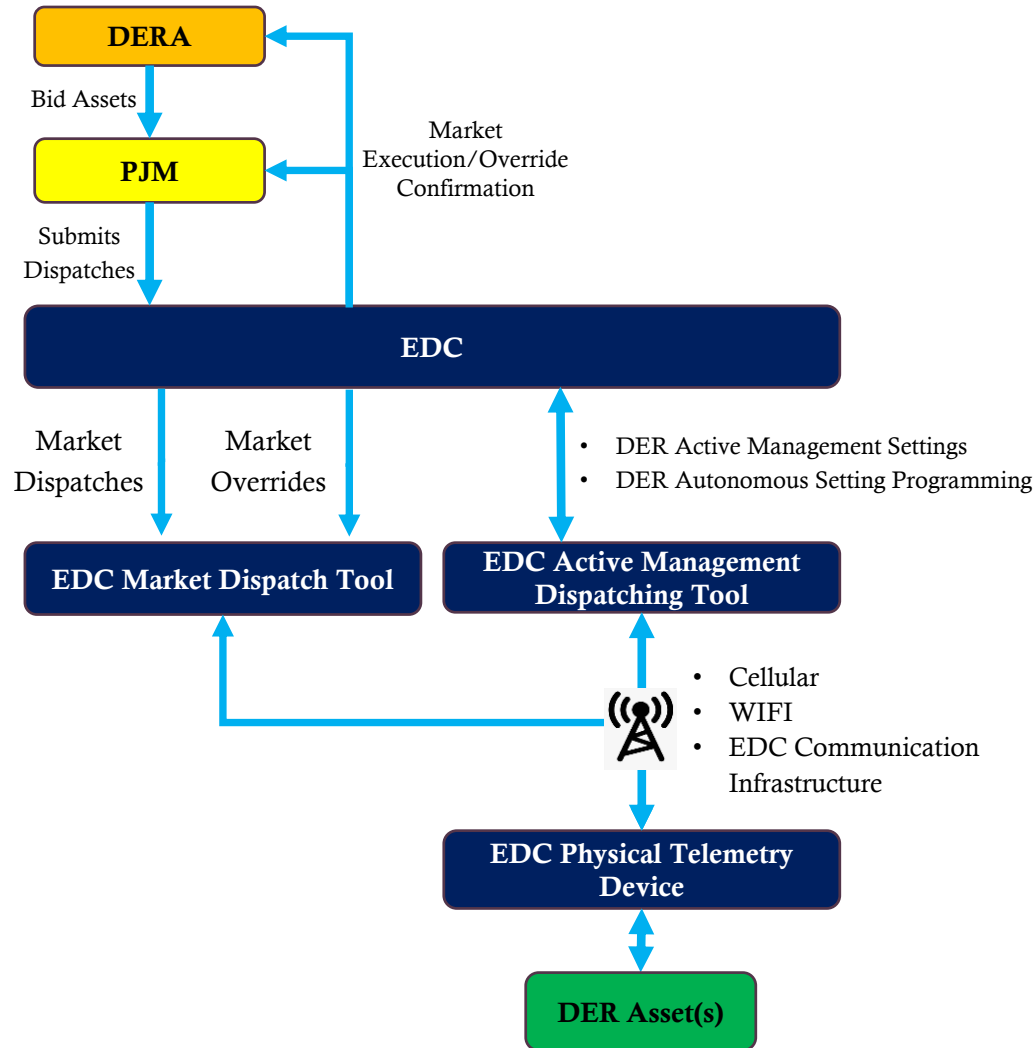
↔ Dependent on additional aggregator permissions

Requires two independent telemetry devices on each DER asset.

Legend for color coding:

- PJM Function
- EDC Function
- DERA Function
- DERA / EDC Function

TELEMETRY MODEL: ADDITIONAL APPROACH



Benefits of Approach

- Allows for combined DER Active Management and Market function considerations in order to maximize device market participation and reduce non-outage related overrides like voltage violations and overloads
- Enables customer to have a single telemetry communication system on customer's residence
- Enables EDC choice on additional telemetry functions permitted by the IEEE 1547.2018 (volt-var curve, ride through curves)
- According to IEEE 1547.2018, a communication port is made available for EDC's use of DER management and monitoring.
- Gives EDC the ability to have oversight on telemetry communication network reliability to ensure effective override capabilities.
- Allows for locational system capabilities regardless of the DERA and even compensatory model (i.e. if customer switches to not participate in market)



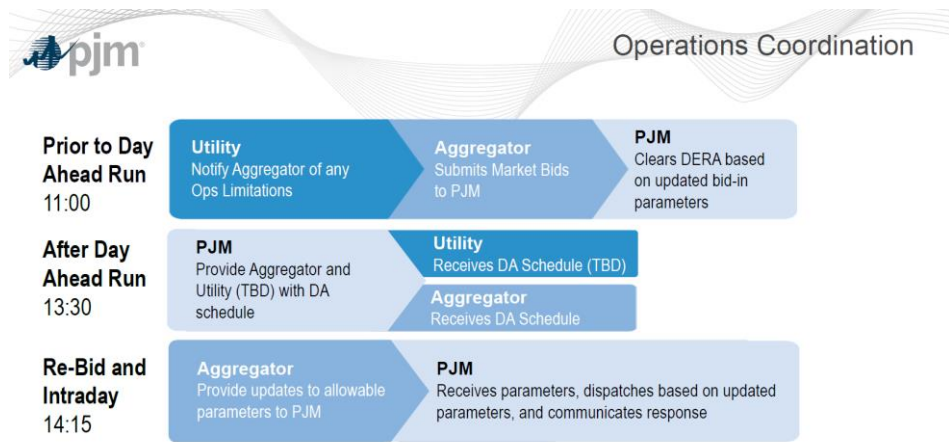
TELEMETRY MODEL: MUST HAVE FLEXIBILITY



- EDC choose the telemetry model at the outset.
- EDC can choose to transition between models over time.

DER MARKET DISPATCH OVERRIDE

OVERIDE DISCUSSION



Discussion Item

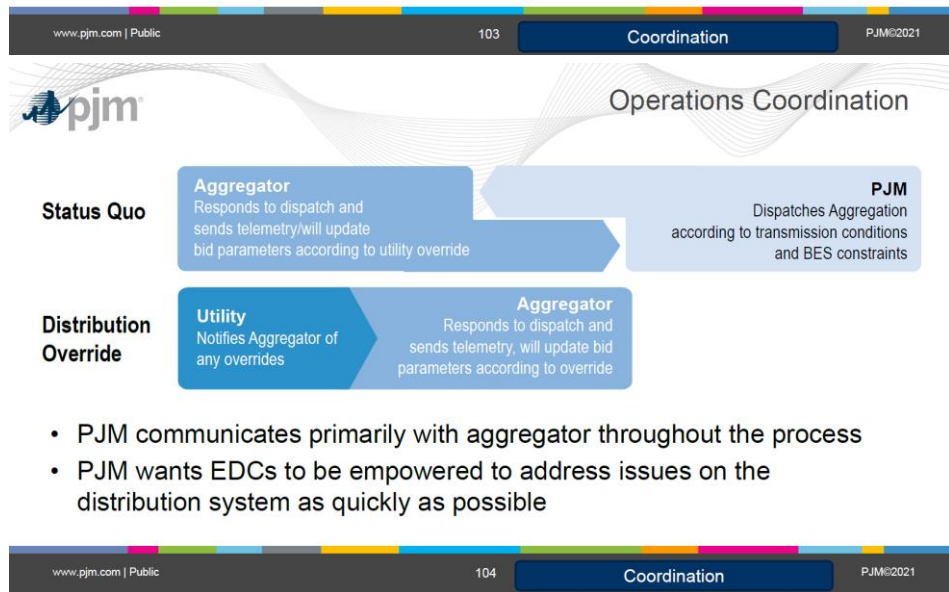
- Proposed EDC coordination slides are interpreted into meaning that the EDC only has the capability to perform post dispatch overrides.

Concerns

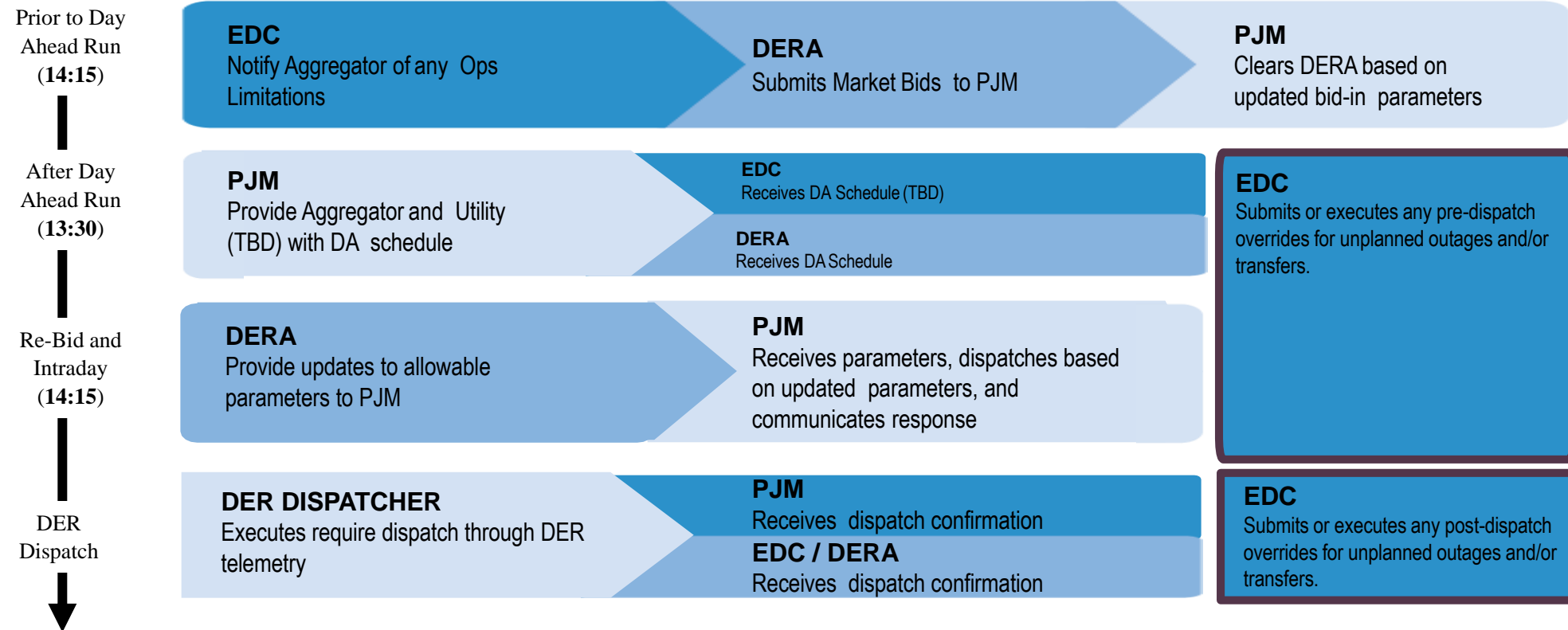
- Reliability and customer power quality need to take precedence over any market financial gain. In order to maintain this philosophy with FERC 2222, EDC's require override capabilities both before and after market dispatches are executed.

Thoughts

- Depending on the DERA dispatcher model, the EDC would either need to send the pre dispatch override to the DERA (DERA Dispatcher Model) or not execute the dispatch (EDC DER Dispatcher Model)



OVERIDE IMPLEMENTATION: TIME FRAMES



OVERRIDE IMPLEMENTATION: EXECUTION

METHODS

Prior to Day Ahead Run (14:15)

Time Frame 1

After Day Ahead Run (13:30)

Time Frame 2

Re-Bid and Intraday (14:15)

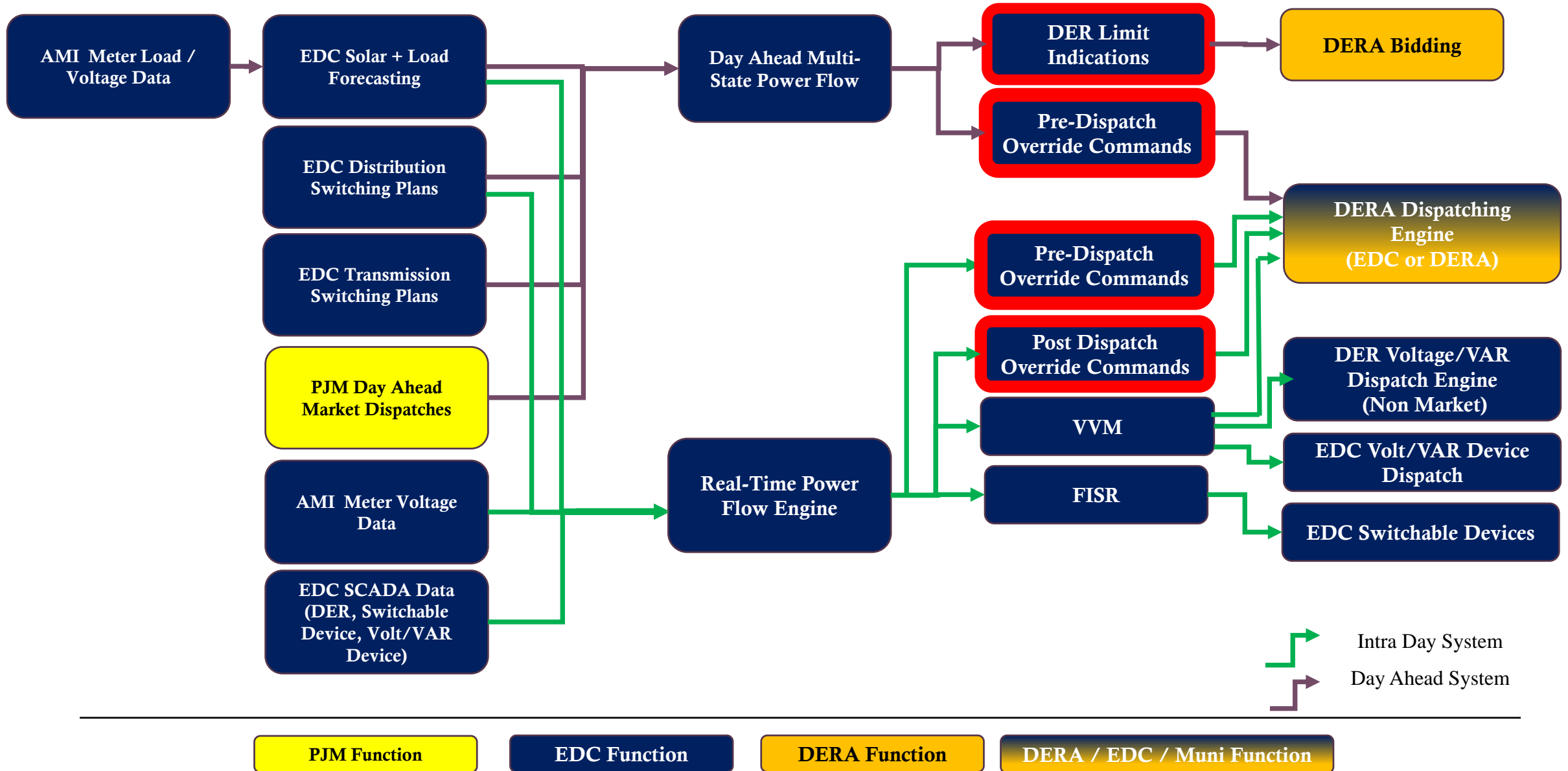
Time Frame 3

DER Dispatch

Time Frame 4

Dispatcher Model	Time Frame 1	Time Frame 2	Time Frame 3	Time Frame 4
DERA As Dispatcher	???	???	???	EDC will send command to DERA for DER asset dispatch. Communication from DERA to PJM will occur confirming override.
EDC As Dispatcher	EDC will scrub specific DER asset(s) from the execution plan. EDC will communicate modifications to dispatch plan to DERA and PJM.	EDC will scrub specific DER asset(s) from the execution plan. EDC will communicate modifications to dispatch plan to DERA and PJM.	EDC will scrub specific DER asset(s) from the execution plan. EDC will communicate modifications to dispatch plan to DERA and PJM.	EDC will send command to DER asset and communicate modifications to dispatch plan to DERA and PJM

OVERRIDE IMPLEMENTATION: DATA FLOW



TRANSFER / OUTAGE SCENARIO DISCUSSION

TELEMETRY MODEL DISCUSSION



- 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

Discussion Item

- Proposed strawman Operational Needs slide along with related market operations slides are somewhat ambiguous on market and operational decisions related to planned and un-planned outages that occur throughout the bulk electric system and distribution systems.

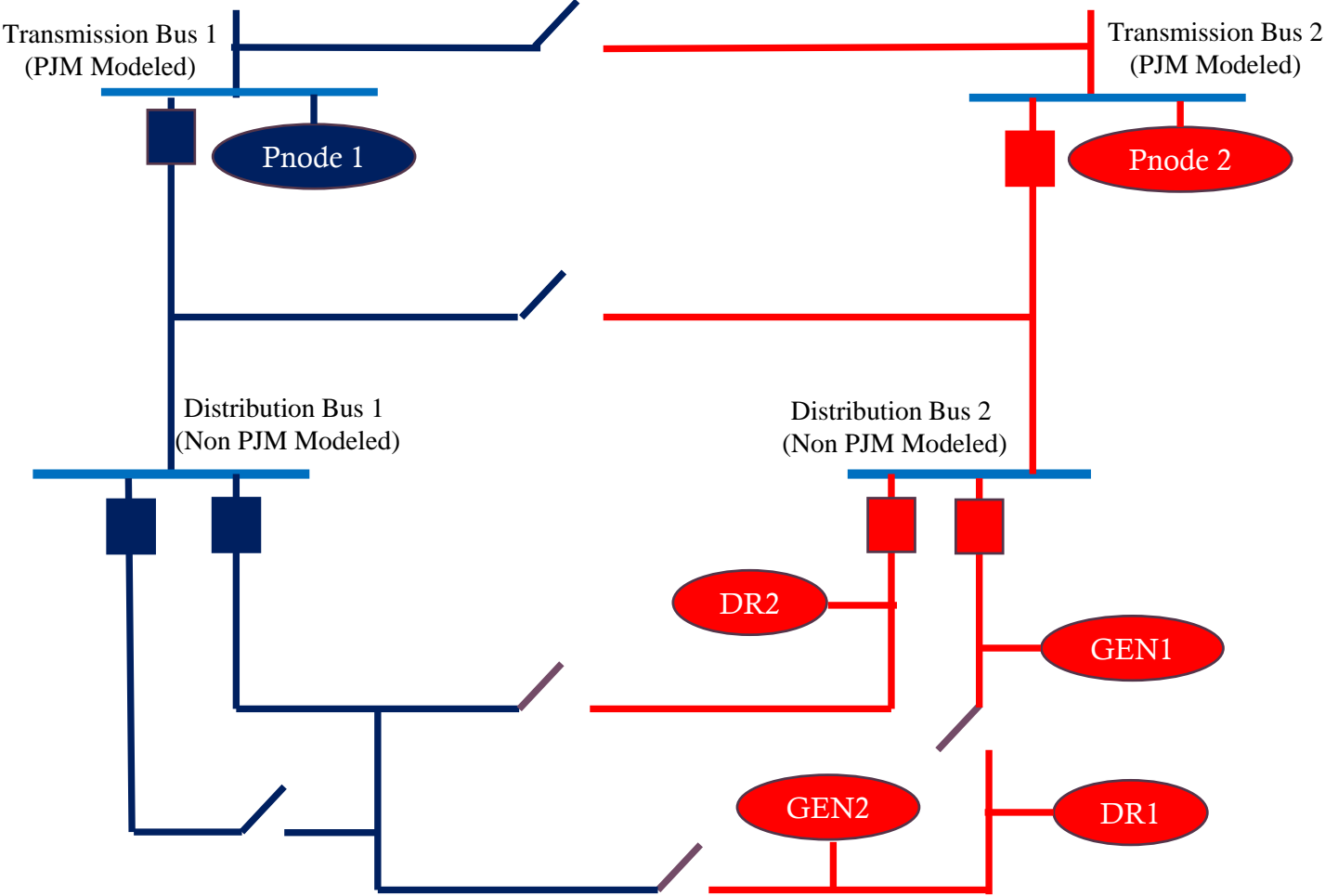
Concerns

- There has been minimal discussion on cause-and-effect scenarios related to PJM requirements that will affect DERA's and EDC alike.
- DER operation outside a market control (i.e. when transferred to a line segment that is not electrically connected to the Pnode).
- DER compensatory model, if any outside a market control timeframe (i.e. when transferred to a line segment that is not electrically connected to the Pnode).

Thoughts

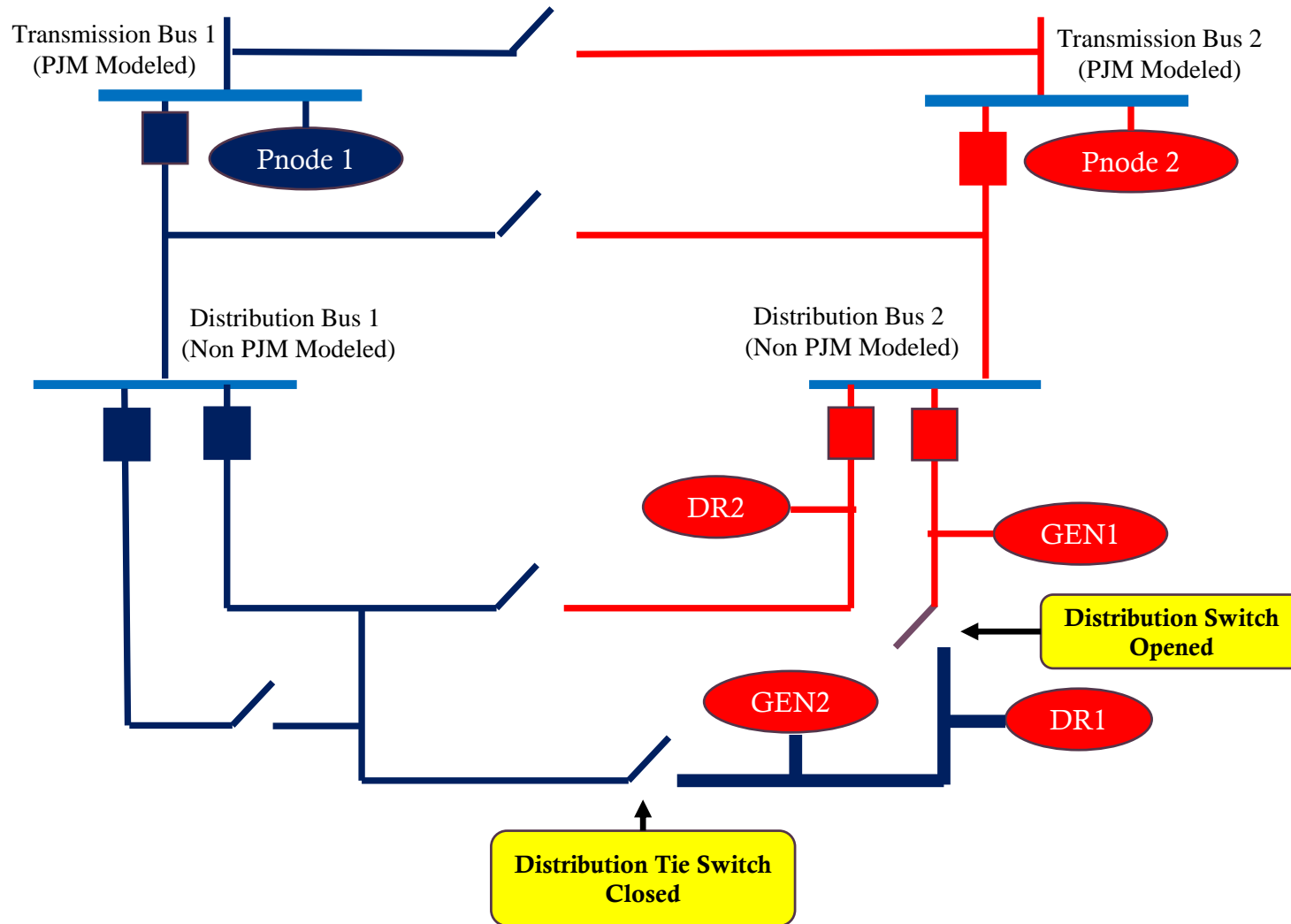
- Need to start discussion on transmission and distribution dynamics in order to identify potential decisions that will need incorporation into the PJM tariff.

SYSTEM EXAMPLE FOR USE CASES



GEN1/2 and DR1/2
part of one DERA
under Pnode 2

USE CASE 1: DISTRIBUTION TRANSFER



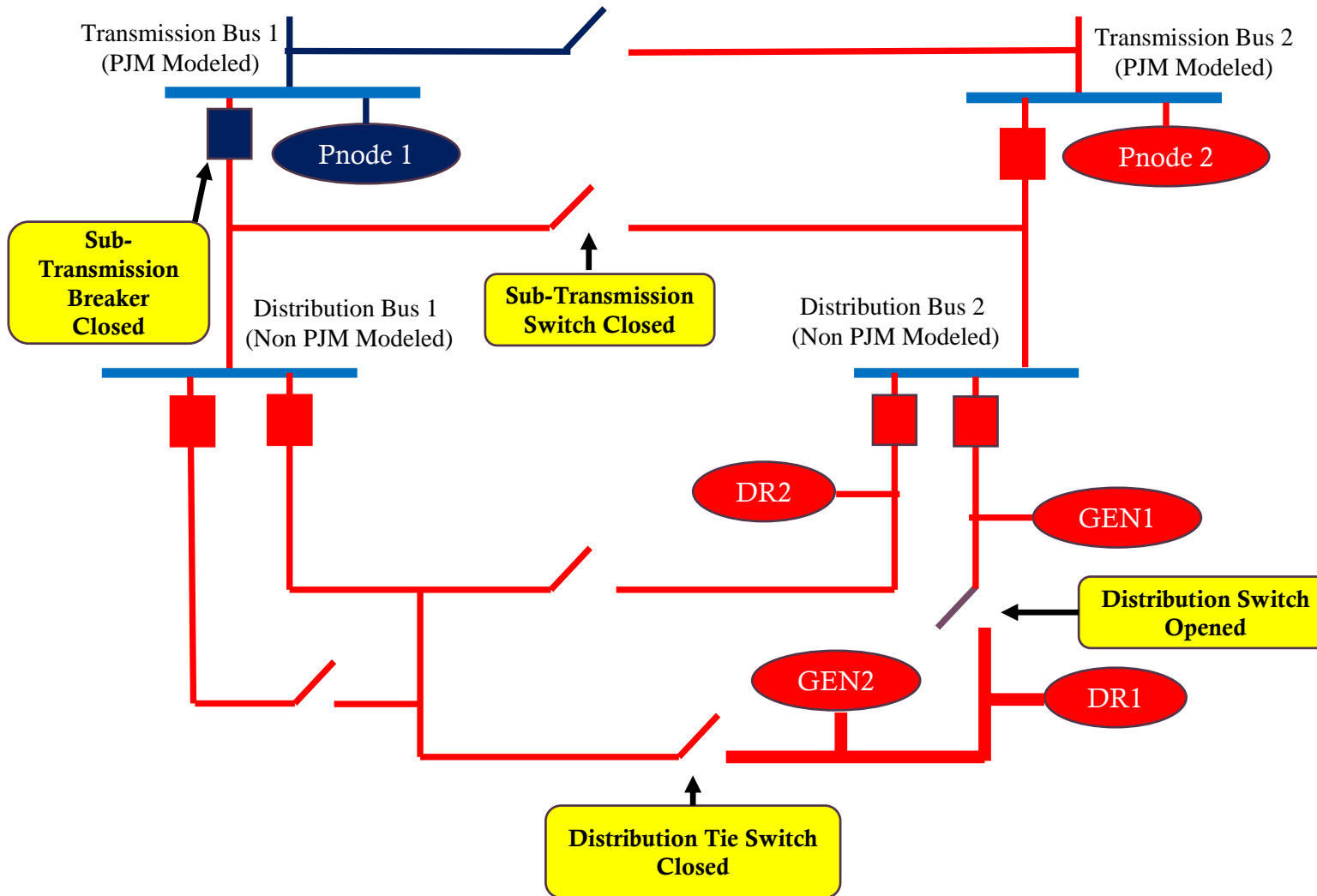
• Situation

- 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?

USE CASE 1: DISTRIBUTION + TRANSMISSION TRANSFER



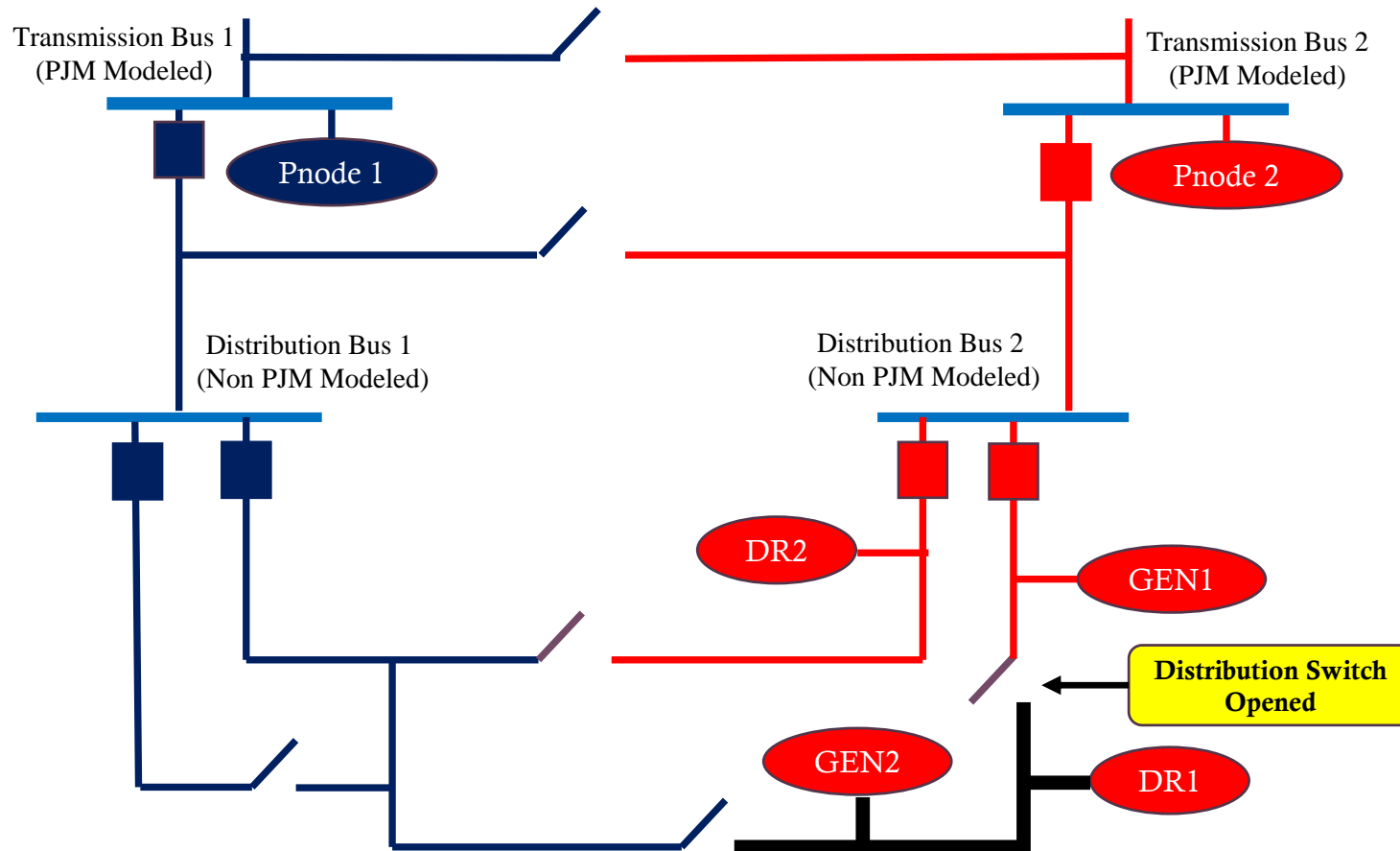
• Situation

- Distribution work requires a section of 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 GEN2 and DR1 in terms of market participation since by two moves they are still under Pnode 2 but connected in a different way.
- What happens to GEN2 and DR1 operationally?
- What happens if the transfer is permanent, or it is for a long duration?

USE CASE 2: DISTRIBUTION OUTAGE



- **Situation**

- Distribution experiences an outage on a line segment.
- GEN1/2 and DR1/2 part of one DERA under Pnode 2
- GEN2 / DR1 either de-energize or remain on if they are tied to an ATS.

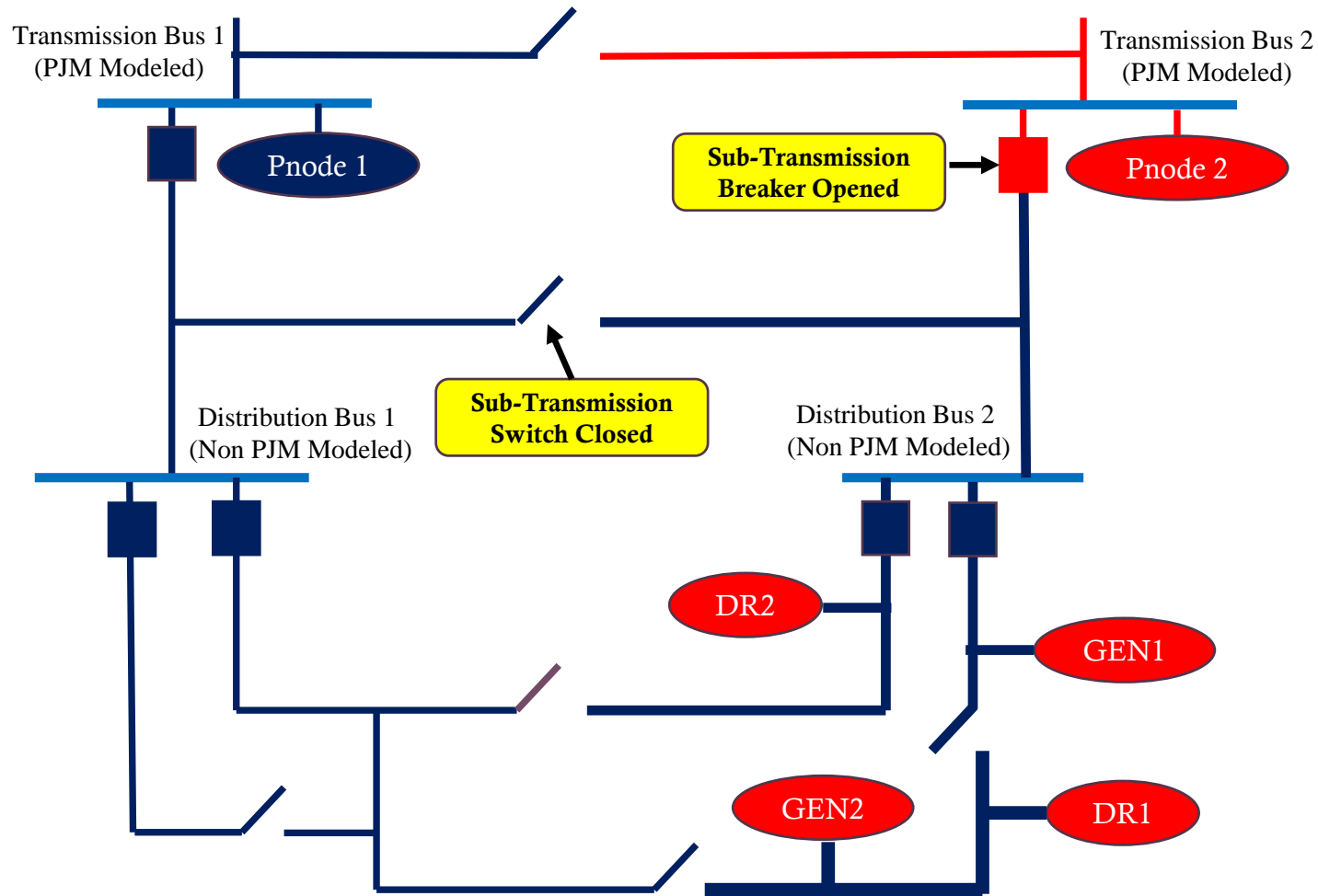
- **Comment**

- It is assumed that that GEN2/DR1 will not participate in the market during the outage.

- **Questions**

- What operational parameters will energy storage / generation and storage assets be permitted during outage if the customer has an automatic transfer switch (aka outage backup)

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?

ADDITIONAL AREAS OF CLARIFICATION

AREAS FOR ADDITIONAL DISCUSSION



Courtesy of Flexis

- Telemetry/metering requirements by each market (energy, ancillary, and capacity); and provide what they are proposing as additional requirements for DERAs operating in those markets
- Considerations with energy storage considerations that have varying state of charge over time.
- Management of Single Customer – Multi-DER Situations
 - Multi DERA condition requirements
 - Telemetry System Setup / Requirements
 - Override Execution (how do the locational overrides get dispersed at specific locations especially with multi DERA situations)
- Involvement of load reduction participants in overrides.
- End-to-end cyber security vetting and compliance tracking.
- Use cases needed to determine telemetry needs:
 - Various DER/DERA configurations
 - EVs/ Movable Storage Assets
 - Movable Generation Assets
 - Microgrids

EDC DATA FLOW DISCUSSION

Presented By Ed Stein

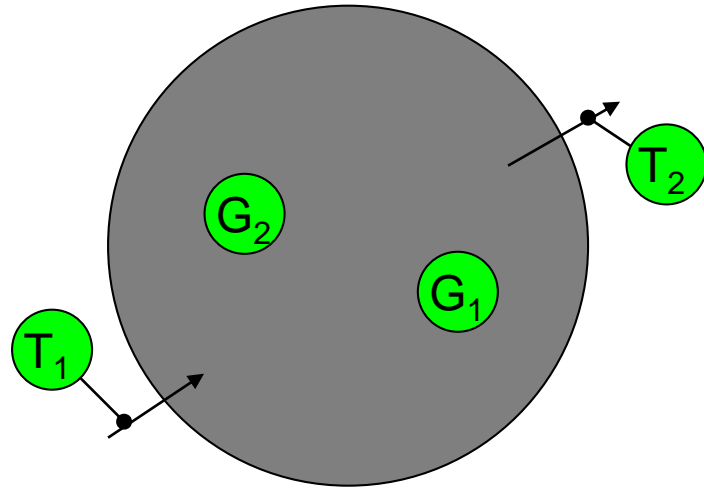
ITEMS TO COVER

- A View of Zonal Construct/Mathematics
- PJM Proposal
 - **PowerMeter Submittals**
- Recommendation
 - **Highlight modifications**



A LOOK AT CURRENT MATHEMATICS & FUNCTIONALIZATION - LOAD

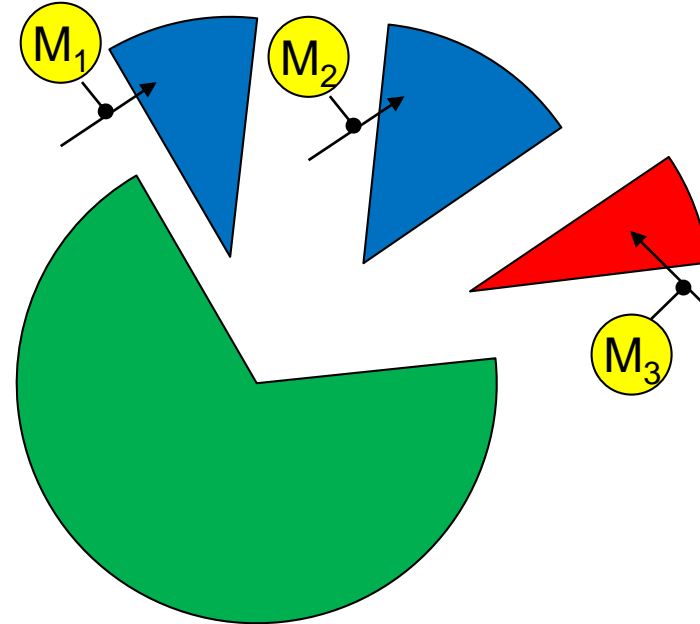
Step 1: TO Determine Zonal Load / Jurisdictional Boundary



TO $LZ = G_1 + G_2 + T_1 - T_2$

Step 1	Unit/Meter	MW	Powermeter
	G1	175	
	G2	250	
	T1	75	
	T2	100	
LZ	400		

Step 2: TO Determine WLR and Residual IOU EDC



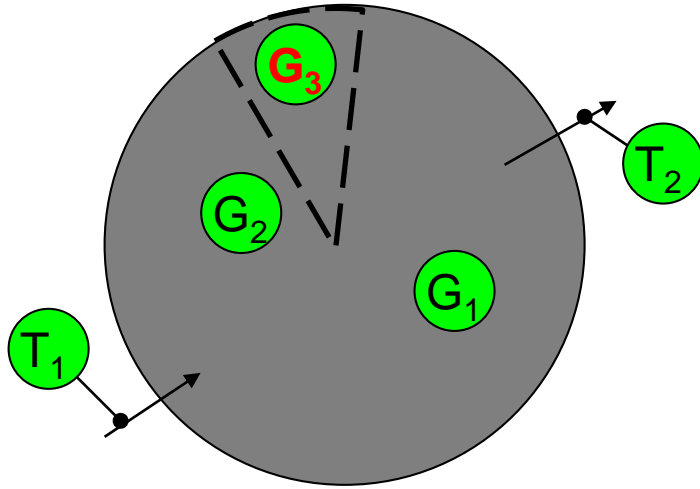
Step 2	Party	Market Participant	Meter	MW	Losses ¹	Final MW	Inschedule Type
	Muni/Coop 1	Aggregator 1	M1	27.3	0.1	30	WLR
	Muni/Coop 2	Aggregator 1	M2	45.5	0.1	50	WLR
	Muni/Coop 3	Muni/Coop 3	M3	36.4	0.1	40	WLR
	IOU EDC Residual	Various by Customer Election	N/A	-	-	280	RLR
	LZ					400	

Note 1: Losses are contractually based. Some are fixed, some use a mathematical translation of hourly marginal loss calculations.

A LOOK AT CURRENT MATHEMATICS & FUNCTIONALIZATION

– GEN²

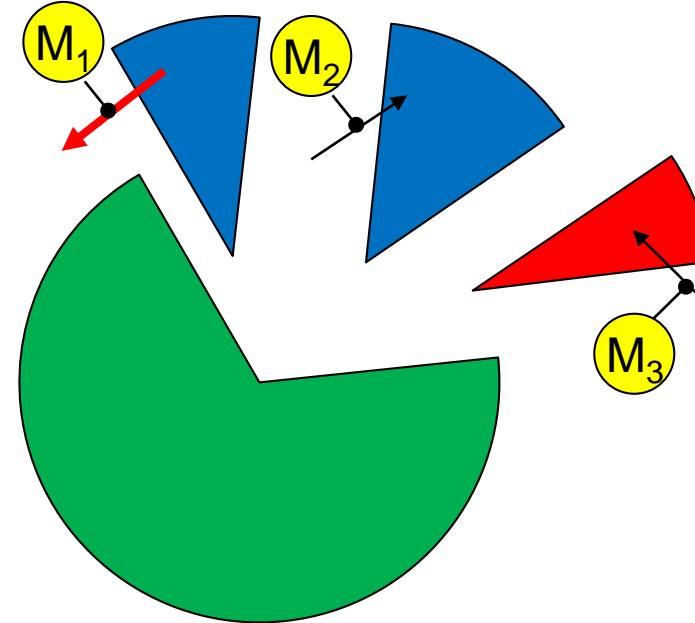
Step 1: TO Determine Zonal Load / Jurisdictional Boundary



$$\text{TO LZ} = G_1 + G_2 + T_1 - T_2 + G_3$$

Step 1	Unit/Meter	MW	Powermeter
	G1	125	
	G2	250	
	G3	50	
	T1	75	
	T2	100	
	LZ	400	

Step 2: TO Determine WLR and Residual IOU EDC



Step 2	Party	Market Participant	Meter	MW	Losses ^{1,3}	Final MW	Inschedule Type
	Muni/Coop 1	Aggregator 1	M1	-20.0	0	=-20+50=30	WLR
	Muni/Coop 2	Aggregator 1	M2	45.5	0.1	50	WLR
	Muni/Coop 3	Muni/Coop 3	M3	36.4	0.1	40	WLR
	IOU EDC Residual	Various by Customer Election	N/A	-	-	280	RLR
	LZ					400	

Note 1: Losses are contractually based. Some are fixed, some use a mathematical translation of hourly marginal loss calculations.

Note 2: Gross generation is submitted to PJM.

Note 3: Losses are not applied to M₁ when negative.

PJM PROPOSAL FOR FO2222 SUBMITTALS OF DERA

PERFORMANCE

- **Under PJM's proposal concepts with the compliance filing, PJM would require a DERA's settlement data be submitted to PowerMeter**
 - **In response to the PowerMeter proposal questions arise:**
 - How is accuracy and completeness of the data enforced?
 - How is zonal load and subsequent calculations of municipality, cooperative and residual IOU load accomplished? Who is the in the best place to calculate all these quantities?
 - Should all Host Distribution Company loads be modeled in PowerMeter?
 - Should PJM calculate all loads and load targets of Host Distribution Companies?
 - **The following two proposals are two takes**
 - Proposal I requires all EDCs be determined centrally by PJM via PowerMeter
 - Proposal II requires those EDCs that elect to do so be centrally calculated by PJM via a combination of PowerMeter and InSchedule
 - **Are there other proposals to answering the questions?**
-

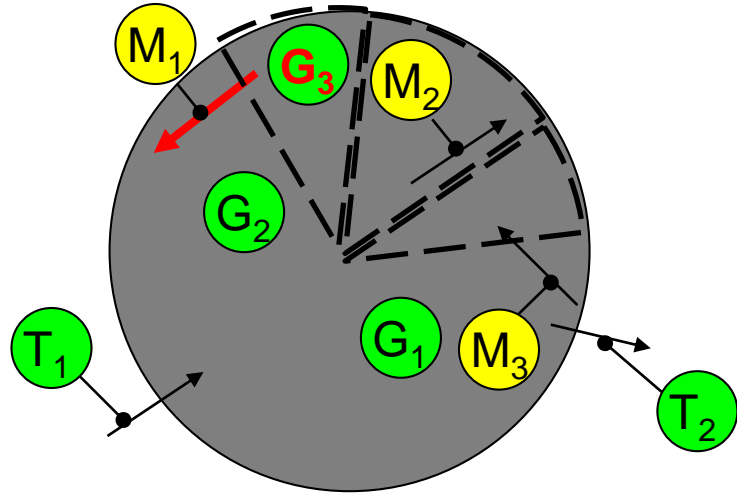
PROPOSAL I: ALL EDCS & POWERMETER SOLUTION

- **Modify EDC energy accounting coordination to increase transparency, align ownership responsibilities and support FERC Order 2222.**
 - All EDCs are members of PJM
 - All EDCs are Fully Metered EDCs
 - All EDC interconnections are modelled in PowerMeter
 - TO/PJM determine all EDC loads (Municipality, Cooperative, IOU)
 - All agree to the methods
 - TOs aid in assuring accuracy and completeness of submitted data (i. e. zonal loads, etc. are correct)
 - All EDCs then assign loads to their respective LSEs
 - PJM allow for if not already there an option to have the load in power default to the Inschedule of the EDCs choice
 - Interconnection agreements modified to reflect updated methods of allocation
-

PROPOSAL I: ALL EDCS & POWERMETER

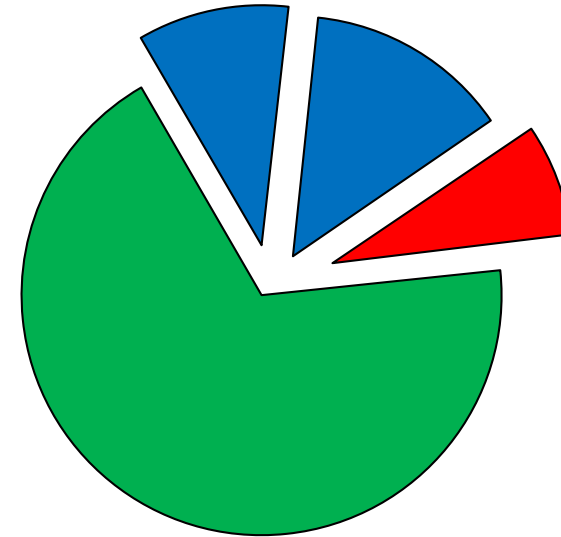
SOLUTION

Step 1: TO/PJM Determine Zonal Load / Jurisdictional Boundary



$$TO LZ = G_1 + G_2 + T_1 - T_2 + G_3$$

Step 2: EDCs determine respective WLR or RLR schedules for which they are responsible.



Step 1	Unit/Meter	MW	Powermeter Submittals
	G1	125	
	G2	250	
	G3	50	
	T1	75	
	T2	100	
	M1 ^{1,3}	-20	
	M2 ^{1,3}	50	
	M3 ^{1,3}	40	

Step 1a - EDC Targets	EDC	MW	Based on Powermeter Submittals
	LZ	400	
	Muni/Coop 1	=-20+50=30	
	Muni/Coop 2	50	
	Muni/Coop 3	40	
IOU EDC Residual	=400-30-50-40=280		

Step 2	Party	Market Participant	Powermeter Target MW	Inschedule Type
	Muni/Coop 1	Aggregator 1	30	WLR/RLR
	Muni/Coop 2	Aggregator 1	50	WLR/RLR
	Muni/Coop 3	Muni/Coop 3	40	WLR/RLR
	IOU EDC Residual	Various by Customer Election	280	RLR
	LZ		400	

Note 1: Losses are contractually based. Some are fixed, some use a mathematical translation of hourly marginal loss calculations.

Note 2: Gross generation is submitted to PJM.

Note 3: Losses are not applied to M₁ when negative.

PROPOSAL II: OPT IN EDCS & POWERMETER/INSCHEDULE SOLUTION

- Under PJM's proposal concepts with the compliance filing, PJM would require settlement data be submitted to PowerMeter
 - DER submission to PJM will increase the total load on the TO LZ EDC; as a result the In schedules will have to increase to account for this load
 - Wholesale Load metering won't capture the load the DER is physically serving because that happens behind the interconnect meters
 - In order to keep DER from being double counted (as both as a load reducer and a Generator in the market), each DER would need to be assigned as load to the load it sits behind
-

PROPOSAL II: OPT IN EDCS & POWERMETER/INSCHEDULE SOLUTION

Issues for PJM to consider

1. DER data will have to be submitted to both PowerMeter (as a Generator) and Inschedule (as a load contract to account for the BTM load being served) – Can PJM set it up so that the data only must be submitted once?
 2. If the data is submitted to PowerMeter it has the issue that Monthly Meter Correction is a monthly total adjustment, but the related Inschedules will need hourly adjustments. Can PowerMeter be updated to receive hourly corrections?
 3. As an alternative to submitting to PowerMeter, could DERS be submitted once to Inschedule and that data be used to increase the TO LZ EDC, Increase the LSE Load for the BTM load, and be used to calculate the payment to the aggregators?
-