PJM Proposal: Reserve Market Enhancements

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Markets & Reliability Committee Meeting
January 24, 2019

Comprehensive Reserve Pricing Reform

The PJM Board has determined that a comprehensive package inclusive of the components outlined below, is needed to meaningfully address the reserve procurement and pricing issues.

1. Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
2. Improved utilization of existing capability for locational reserve needs
3. Alignment of market-based reserve products in Day-ahead and Real-time Energy Markets
4. Operating Reserve Demand Curves (ORDC) for all reserve products
5. Increased penalty factors to ORDCs to ensure utilization of all supply prior to a reserve shortage
6. Transitional mechanism to the RPM Energy and Ancillary Services (E&AS) Revenue Offset to reflect expected changes in revenues in the determination of the Net Cost of New Entry

Component #1: Consolidation of Tier 1 and Tier 2 and Offer Changes

Tier 1 Market Product

Remaining ramping capability on flexible dispatchable generation resources after economic dispatch

- 10-minute response time
- Obligation to respond
- Non-compliance penalty
- Paid for response to an event

Vs.

Tier 2 Market Product

- Generation resources reduced from their economic set point
- Synchronous condensing resources and DR

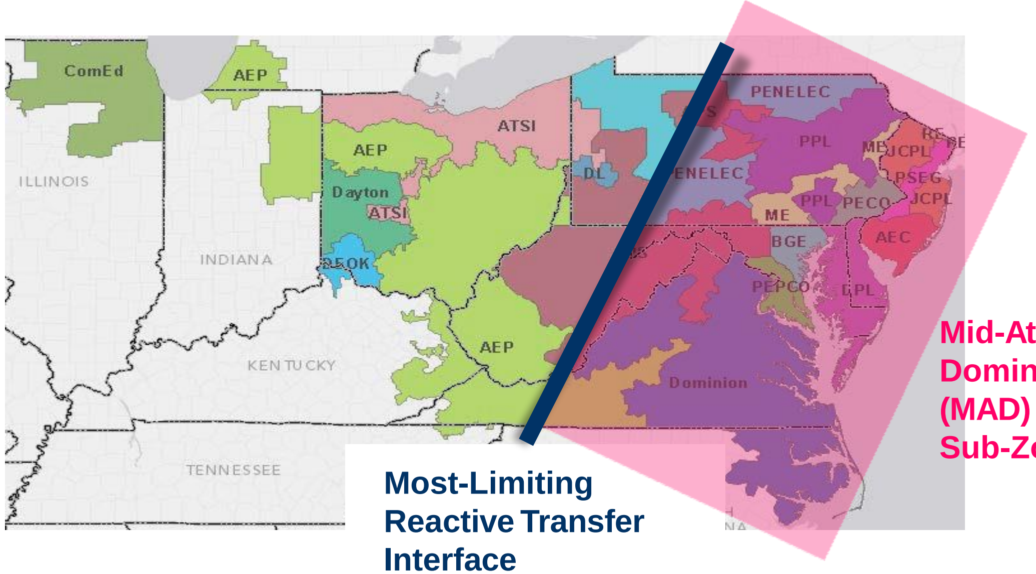
- 10-minute response time
- Obligation to respond
- Non-compliance penalty
- Paid market clearing price regardless of deployment

Component #1: Consolidation of Tier 1 and Tier 2 and Offer Changes

- PJM will strengthen the synchronized reserve must offer requirement
- PJM will calculate a resource’s availability and reserve offer MW using the availability and unit parameters offered in for energy, with some exceptions
  - Participants will be provided additional flexibility to update energy ramp rates intra-day and to update the Synch Reserve Maximum MW intra-hour to enable more accurate representation of their reserve capability
- The proposal reduces the maximum level of synchronized reserve offers.
  - The Variable Operations & Maintenance component will be removed from SR offers (it is already included in energy offers)
  - The $7.50/MWh offer margin will be reduced to the expected value of the penalty ($0.02 for 2018).

Component #2: Flexible Reserve Zone Modeling

- More Flexible Reserve Sub-Zone Modeling
  - Keep existing RTO reserve zone with closed loop sub-zone structure, but allow flexibility to change the location of the sub-zone on a day-ahead basis, as needed
    - Allow changes intraday on an exception basis
  - Define several reserve sub-zones, of which only one will be used at a time



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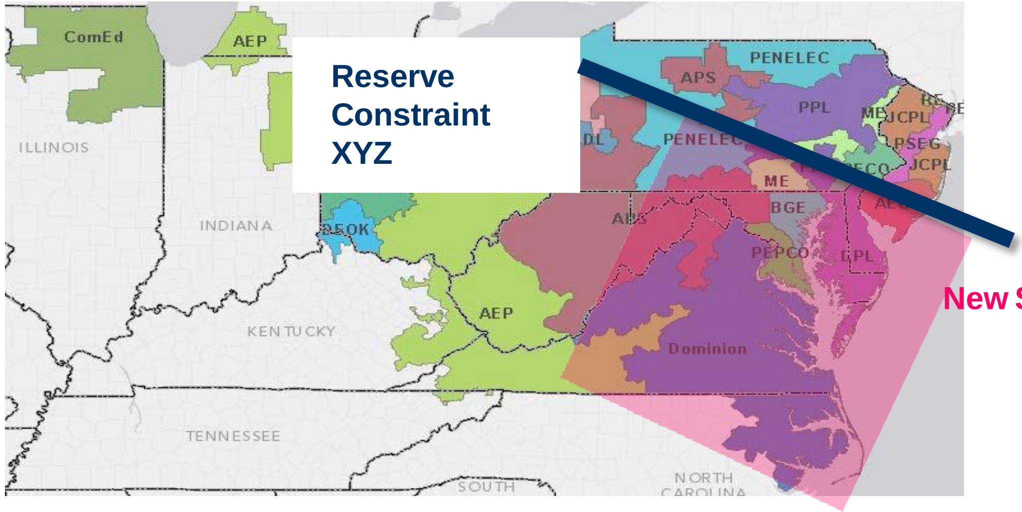
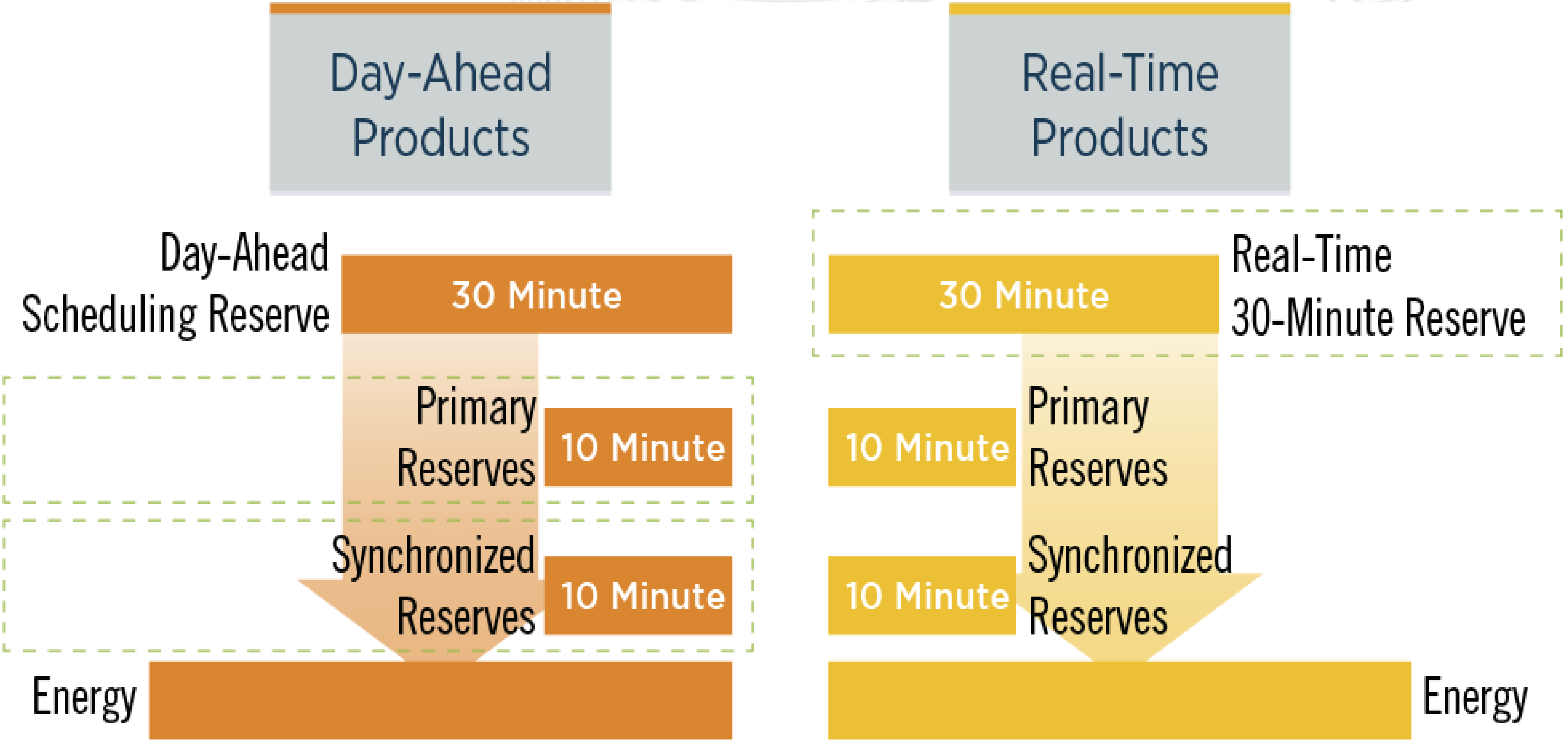


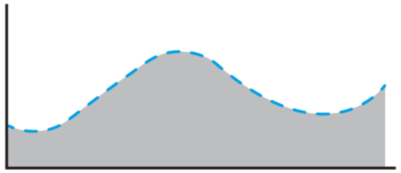
Component #3: Reserve Market Alignment



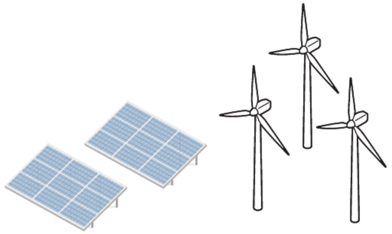
ORDCs and Offer Price Caps will be consistent between DA & RT for each product

Component #4: Implement Downward-Sloping Demand Curves

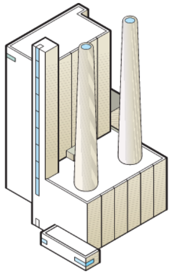
- Basis for value is the cost of a reserve shortage and the uncertainty on the system that could result in falling below the reserve requirement despite procuring sufficient reserves in advance
  - Cost of a reserve shortage is based on the penalty factor
  - Uncertainty is measured from historical data:



Real-time load forecast



Real-time solar and wind forecast



Expectation of conventional generator failure

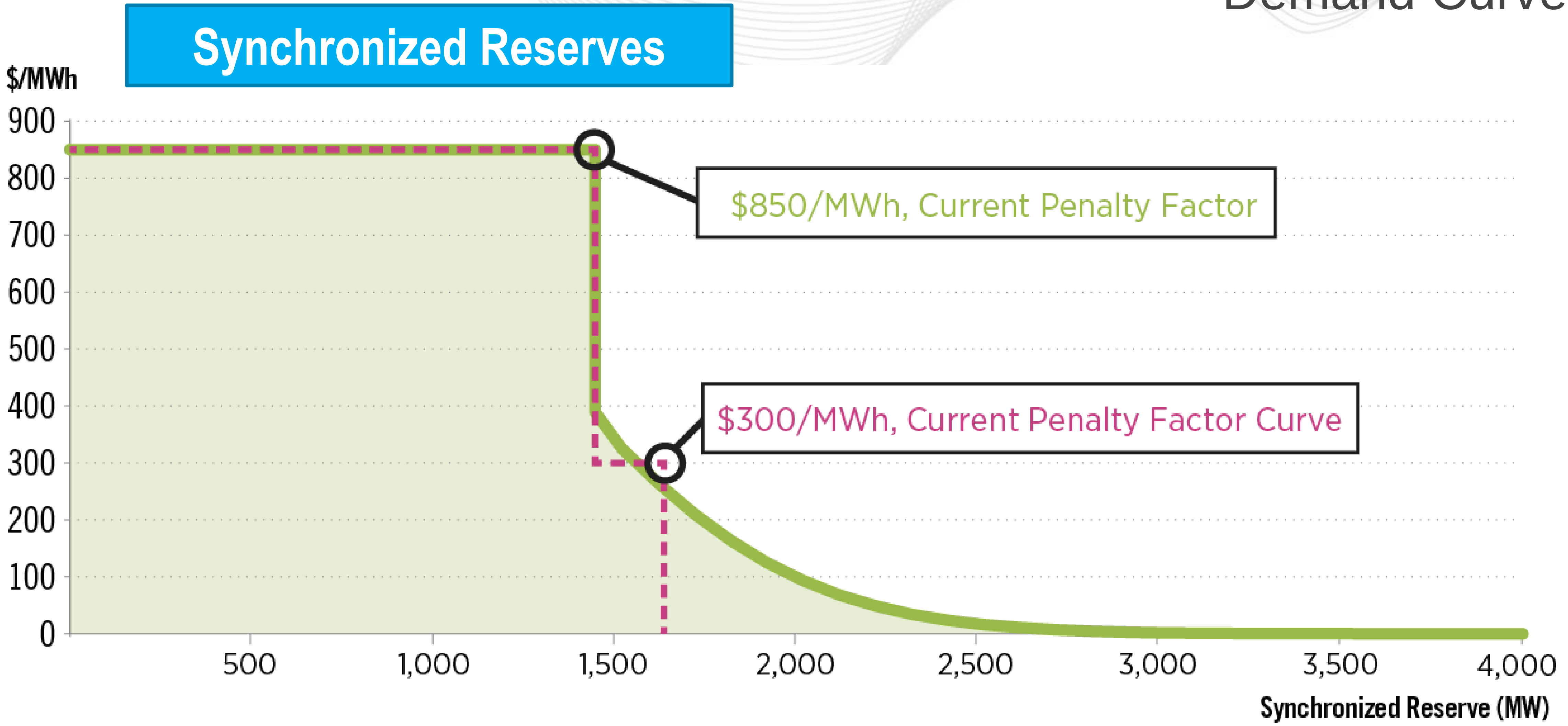
Component #4: Implement Downward-Sloping Demand Curves

- The Regulation Requirement (shown below) is used to deal with the uncertainties mentioned in the previous slides.

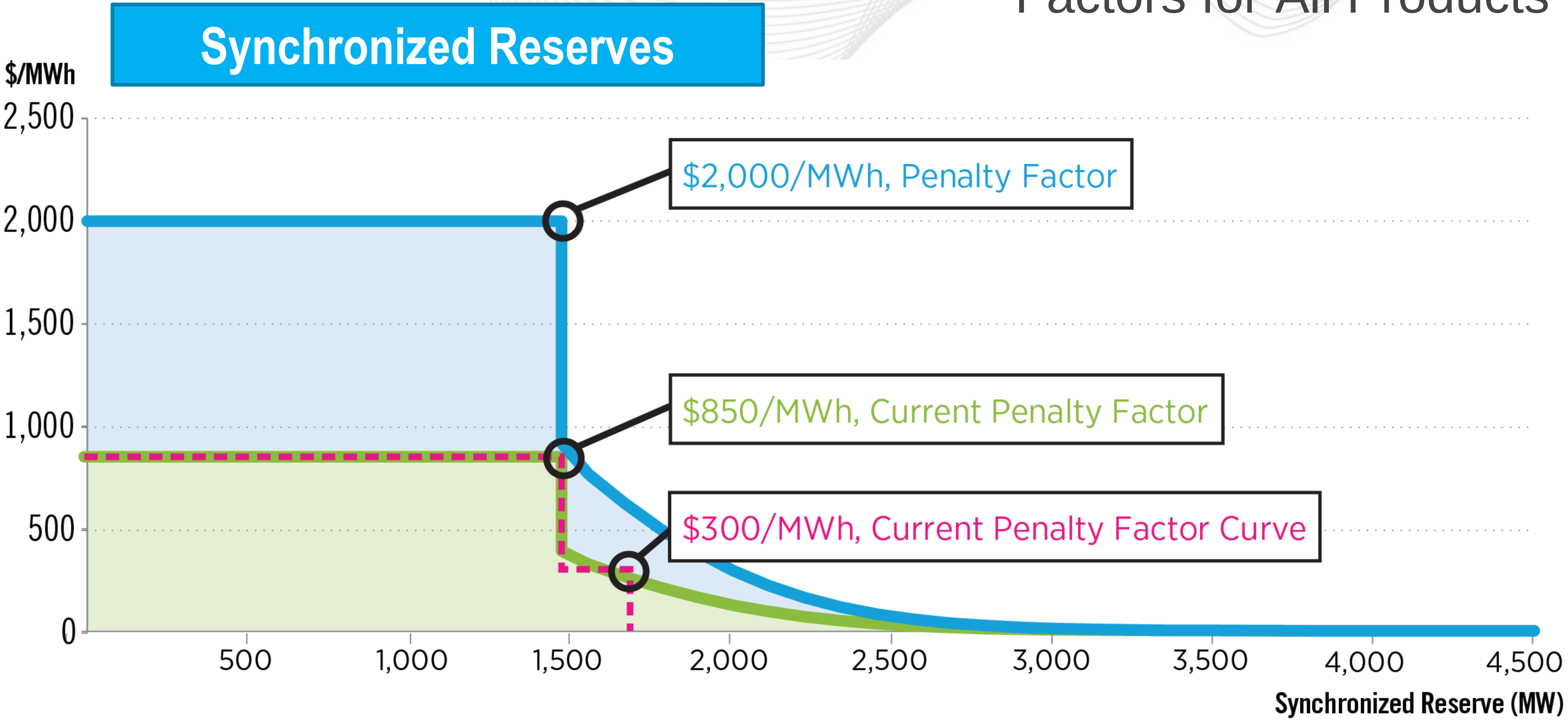
Season	Dates	Non-Ramp Hours	Ramp Hours	Effective MW Requirement
Winter	Dec 1 – Feb 29	HE1 – HE4, HE10 – HE16	HE5 – HE9, HE17 – HE24	Non-Ramp = 525MW Ramp = 800MW
Spring	Mar 1 – May 31	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW
Summer	Jun 1 – Aug 31	HE1 – HE5, HE15 – HE18	HE6 – HE14, HE19 – HE24	Non-Ramp = 525MW Ramp = 800MW
Fall	Sep 1 – Nov 30	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW

- The ORDCs can be shifted to the left by the regulation requirement
  - *Update based on feedback:* PJM is studying historic regulation deployment data to determine if there is a better method to account for regulation in the ORDC.

Component #4: Implement Downward-Sloping Demand Curves



Component #5: Implement $2,000/MWh Penalty Factors for All Products



Component #5: Implement $2,000/MWh Penalty Factors for All Products

PJM dispatchers will commit high-cost generation and deploy pre-emergency and emergency load management reductions, which have a cost in excess of the existing $850 penalty factor, in order to maintain Synchronized and Primary Reserves.

- Generation offer cap (for price-setting): $2,000/MWh
- Offer cap for Pre-Emergency and Emergency Load Management Reduction Actions:

Lead Time	Offer Cap Formula	Offer Cap
2 hours	$1,000 plus the Primary Reserve Penalty Factor	$1,100/MWh
1 hour	$1,000 plus (the Primary Reserve Penalty Factor * ½)	$1,425/MWh
30 minutes	$1,000 plus (the Primary Reserve Penalty Factor -$1)	$1,849/MWh

The Penalty Factor should be revised to $2,000/MWh to allow these operator actions to be reflected in market pricing

Also need to revise Pre-Emergency and Emergency Load Management Reduction offer caps to remove circular reference

Component #6: Transition

- The goal of the E&AS adjustment is to reflect the additional E&AS revenues anticipated to be created by this proposal in the capacity market.
- PJM proposes to simulate the Energy and Reserve Market outcomes based on actual operating conditions, but with the proposed reserve market modifications, for Base Residual Auctions held after FERC approval is received.
- The revenues from these simulations will be used to scale the revenues normally used to determine the E&AS offset.

Auction Execution Date	Delivery Year	Revenue Year	Revenue Calculation
May 2020	2023/2024	2017	Scaled
		2018	Scaled
		2019	Scaled
May 2021	2024/2025	2018	Scaled
		2019	Scaled
		2020	Half Scaled + Half Actual
May 2022	2025/2026	2019	Scaled
		2020	Half Scaled + Half Actual
		2021	Actual
May 2023	2026/2027	2020	Half Scaled + Half Actual
		2021	Actual
		2022	Actual
May 2024	2027/2028	2021	Actual
		2022	Actual
		2023	Actual

* For illustration purposes, this chart assumes May 2020 is the first Base Residual Auction held after FERC approval is received and the changes are implemented in June 2020

Component #6: Transition

- PJM's ideal path is to implement the following as Phase 1:
  - Tier 1/Tier 2 consolidation and offer changes
  - Enhanced locational reserve zone modeling
  - Downward-sloping demand curves with $850/MWh PFs
  - RT 30-minute reserve market
  - DA and RT reserve market alignment

- Phase 2 would be an increase in the PFs to the final state. Any further transition steps (i.e. – E&AS offset simulations) would be dependent on that final state.

Component #6: Transition

- Phase 1 would be implemented as soon as practicable following FERC approval, potentially on the first day of the Delivery Year. The E&AS offset would be adjusted in the next BRA.

- Phase 2 would be implemented June 1, 202X.
  - 202X is the first year for which the E&AS revenues using the $2,000/MWh PF can be reflected in the E&AS offset.

