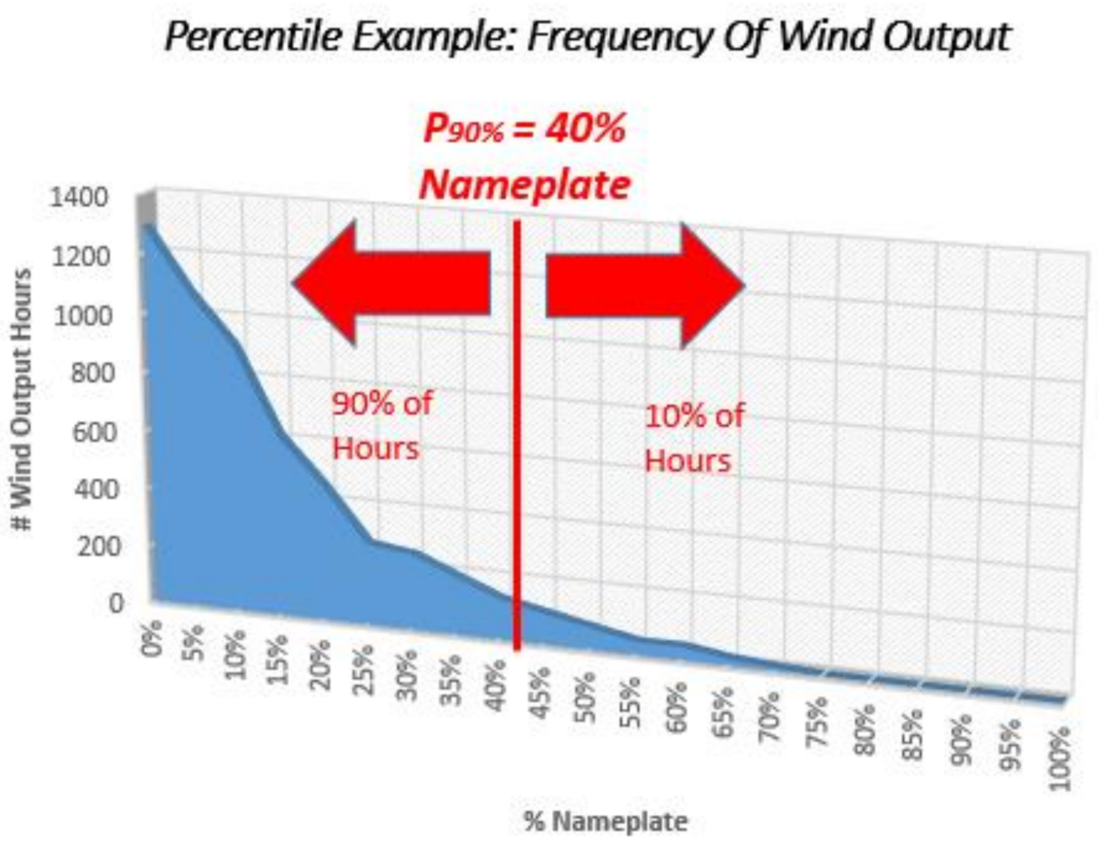
Generator Deliverability Test Modifications: Light Load, Summer & Winter

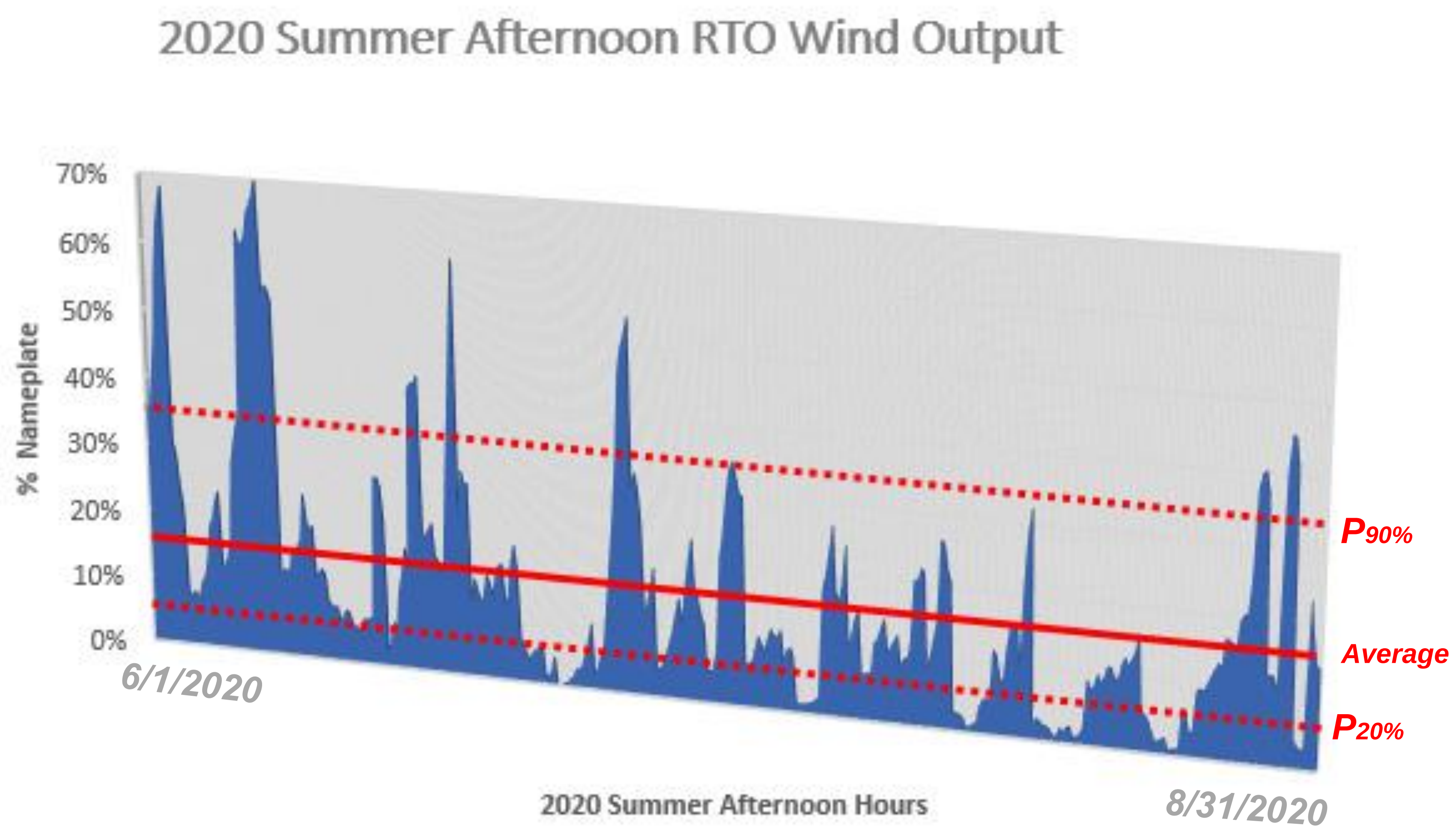
- PJM is proposing modifications to each of the generator deliverability tests.
  - Procedures have been relatively unchanged for many years.
  - Multiple reasons for an update
    - Better account for expected higher variability in dispatches under increased renewable penetration
    - Better planning alignment with operations supporting operational performance

New Concept: Percentiles

- Percentiles: Represent the percentage of output hours with output levels at or below a particular output level.
- Example: if the $P_{90\%}$ (90^{th} percentile) of onshore wind outputs is 40% of nameplate, this means that 90% of the time onshore wind is producing less than 40% of nameplate.



New Concept: Percentiles



New Concept: Block Dispatch

- Block Dispatch: Groups resource types into three distinct categories based on economic considerations with block 1 containing the units expected to have the lowest offer prices and block 3 to have the highest. Each block will be dispatched as whole and block 1 will be dispatched first, then block 2 and 3 as needed
  - Block 1: Nuclear, wind, solar, hydro, pumped storage, other renewables
  - Block 2: Coal, combined cycle gas
  - Block 3: IC/CT/ST oil and gas
- As explained on next slide, block dispatch better matches how the PJM dispatches the system than status quo approach which relies on flat dispatch for summer and historic conditions to dispatch the winter and light load cases

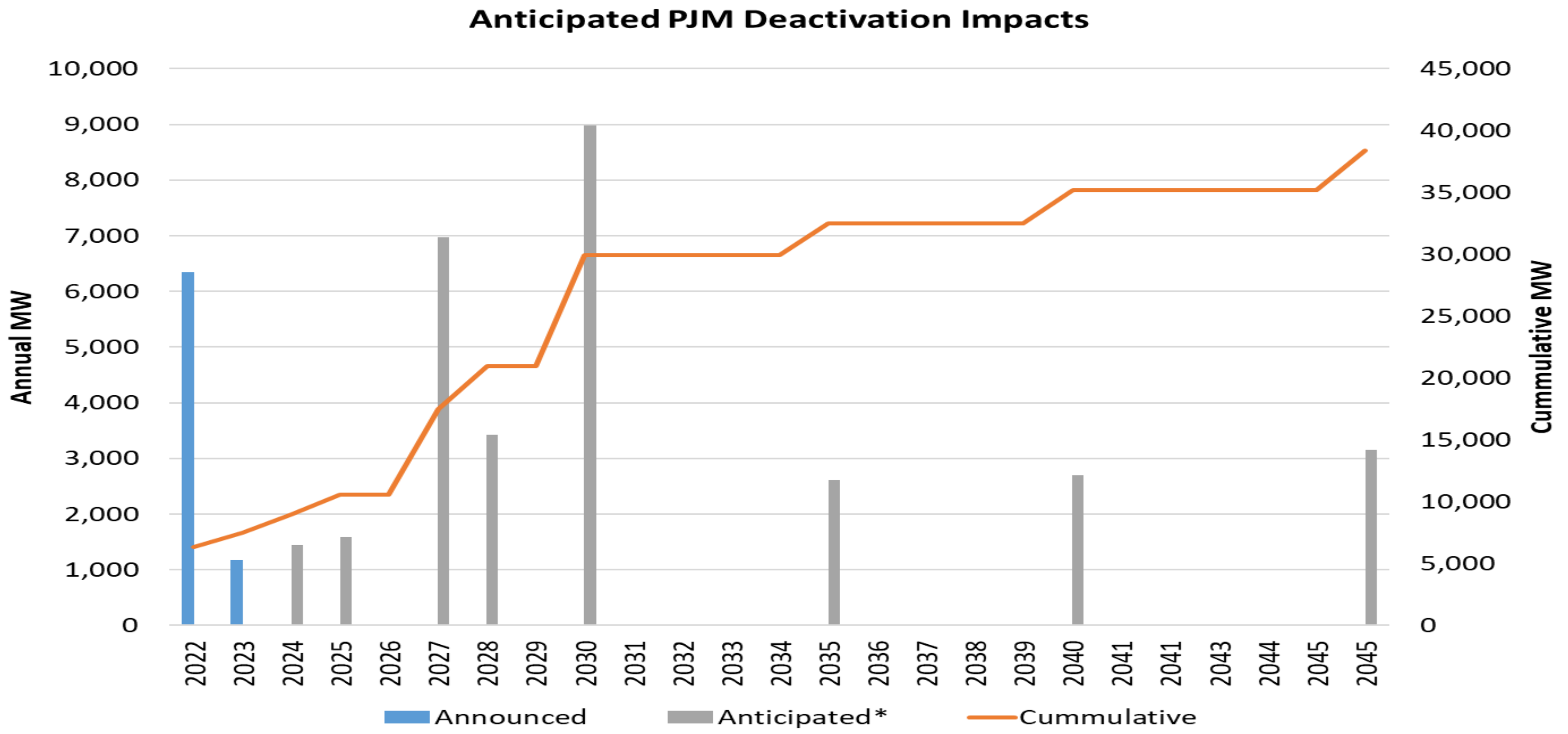
New Concept: Block Dispatch

- **Status quo summer dispatch**
  - Every Capacity Resource is online, outputting the same percent of their Capacity Interconnection Rights (CIRs), except for nuclear units which are not allowed to go below minimum output level
  - In the current year RTEP each unit is online at 80% of its CIRs
- **Concerns with status quo summer dispatch**
  - Output levels of every unit is highly dependent on the amount of reserves available
  - In actual summer operations, Block 1 and Block 2 units would be operating at higher levels and Block 3 would be operating at lower levels

New Concept: Block Dispatch

- **Status quo winter and light load dispatch**
  - Every generator is online based on historic capacity factor for the fuel type for the period
  - Internal PJM interchange values are held at historic values
- **Concerns with status quo winter and light load dispatch**
  - Not based on the principles of how generators are actually dispatched in operations
  - Reactive in its treatment of deactivations and future generation changes and not robust enough to handle a future generation fleet that looks very different than it has in the past

Projected PJM Deactivations



* Anticiapted MW are estimated from active or pending legislative rules' criteria and public information (e.g. public emissions reporting). Actual deactivation date may differ from assumptions. Approximately 17,500 MW of EPA CCR impacted plants are currently not included due to retrofits and conversion to dry ash.

Summary of Changes
(Generation Deliverability Tests)

- Percentiles validated through ELCC studies which demonstrated selected levels were appropriate
- Instead of using average output levels, better account for volatility of wind and solar by using $P_{80\%}$-$P_{90\%}$ for Harmers and $P_{20\%}$ for Helpers in all generator deliverability tests
  - Harmers are generators that contribute to facility loadings
  - Helpers are generators that back off facility loadings
- Introduce Block Dispatch procedure to better reflect actual and future dispatch procedures in Operations
- Other miscellaneous improvements such as harmonizing summer, winter and light load dispatch and contingency analysis

RTEP Baseline – Proposal Impact Summary

Violation Driver		Summer	Winter	Light Load	Total
Higher Intermittent	# of Violations:	2	0	2	4
	$M Cost	$ 7.00	$ -	$ 12.00	$ 19.00
Block Dispatch	# of Violations:	1	1	7	9
	$M Cost	$ 28.00	$ 8.50	$ 118.00	$ 154.50
Block Dispatch + Lower Intermittent Helpers	# of Violations:	2	0	0	2
	$M Cost	$ 11.50	$ -	$ -	$ 11.50
Impact of All Drivers	# of Violations:	5	1	9	15
	$M Cost	$ 46.50	$ 8.50	$ 130.00	$ 185.00

- Nine of the 15 violations in the table above were driven by single contingency events and only four of these violations have not been observed as binding constraints in operations over the past couple of years.
- These are the four violations in the first row in the table above, which are driven by higher deliverability of intermittent resources that are not in service yet.

Queue Scenario Using Commercial Probabilities: Summer Peak

- The number of violations is comparable between the status quo and proposal.
- The number of single contingency violations went up and the number of common mode outage violations went down primarily because of the change in the deliverability levels

# Summer Overloads	Status Quo	Proposal
Single Contingency	74	141
Common Mode Outage	286	193
Total	360	334

		Generator Deliverability Harmer Ramping			
		Single Contingency		Common Mode Outage	
Period	Resource Type	Existing	Proposed*	Existing	Proposed*
Summer	Fixed Solar	38%	67-77%	100%	67-77%
Summer	Tracking Solar	~60%	84-89%	100%	84-89%
Summer	Onshore Wind	13%	38-52%	100%	38-52%
Summer	Offshore Wind	~30%	68-73%	100%	68-73%

*Proposed values vary based on which region resource is located in

Red Font = CIR MW used as deliverability requirement

Queue Scenario Using Commercial Probabilities: Light Load & Winter

- Winter was not studied because the proposed intermittent resource deliverability levels are comparable to the status quo
- Light load overloads primarily driven by higher deliverability requirements for solar
- Status quo light load considers nighttime only

# Light Load Overloads	Status Quo	Proposal
Single Contingency	38	114
Common Mode Outage	8	48
Total	46	162

		Generator Deliverability Harmer Ramping			
		Single Contingency		Common Mode Outage	
Period	Resource Type	Existing	Proposed*	Existing	Proposed*
Light Load	Fixed Solar	0%	78-87%	0%	78-87%
Light Load	Tracking Solar	0%	82-86%	0%	82-86%
Light Load	Onshore Wind	80%	66-80%	80%	66-80%
Light Load	Offshore Wind	80%	90-93%	80%	90-93%

* Proposed values vary based on which region resource is located in

Light Load Discussion

- The PJM light load procedure was first introduced in 2011 to address Operational Performance issues caused by wind. There was very little wind at the time.
- The table below shows how wind a solar has grown since 2011 and illustrates just how much more growth is anticipated

	Solar (MW)		Wind (MW)	
Reference	**Nameplate**	**Capacity**	**Nameplate**	**Capacity**
2011 Introduction of Light Load Procedure	19	7	4,679	691
2022/23 BRA	3,243	1,512	8,518	1,728
2026 RTEP	8,860	4,664	13,340	1,905
Queue scenario with commercial probabilities	46,514	27,308	25,771	5,208

APPENDIX

Summary of Base Case Dispatch Changes For Wind & Solar

		Base Case Dispatch	
Period	**Resource Type**	**Existing**	**Proposed***
Summer	Fixed Solar	38%	38%
Summer	Tracking Solar	~60%	~60%
Summer	Onshore Wind	13%	13%
Summer	Offshore Wind	~30%	~30%
Winter	Fixed Solar	5%	5%
Winter	Tracking Solar	5%	5%
Winter	Onshore Wind	33%	40-43%
Winter	Offshore Wind	60%	55-57%
Light Load	Fixed Solar	0%	52-59%
Light Load	Tracking Solar	0%	54-58%
Light Load	Onshore Wind	40%	29-34%
Light Load	Offshore Wind	60%	46-49%

* Proposed values vary based on which region resource is located in

Red Font = CIR MW

Summary of Harmer Ramping Levels For Wind & Solar

		Generator Deliverability Harmer Ramping			
		Single Contingency		Common Mode Outage	
Period	**Resource Type**	**Existing**	**Proposed***	**Existing**	**Proposed***
Summer	Fixed Solar	38%	67-77%	100%	67-77%
Summer	Tracking Solar	~60%	84-89%	100%	84-89%
Summer	Onshore Wind	13%	38-52%	100%	38-52%
Summer	Offshore Wind	~30%	68-73%	100%	68-73%
Winter	Fixed Solar	10%	5%	100%	5%
Winter	Tracking Solar	10%	5%	100%	5%
Winter	Onshore Wind	80%	73-84%	100%	73-84%
Winter	Offshore Wind	80%	96-98%	100%	96-98%
Light Load	Fixed Solar	0%	78-87%	0%	78-87%
Light Load	Tracking Solar	0%	82-86%	0%	82-86%
Light Load	Onshore Wind	80%	66-80%	80%	66-80%
Light Load	Offshore Wind	80%	90-93%	80%	90-93%

* Proposed values vary based on which region resource is located in

Red Font = CIR MW

Summary of Helper Ramping Changes For Wind & Solar

		Generator Deliverability Helper Ramping			
		Single Contingency		Common Mode Outage	
Period	Resource Type	Existing*	Proposed**	Existing*	Proposed**
Summer	Fixed Solar	38%	28-35%	38%	28-35%
Summer	Tracking Solar	~60%	38-48%	~60%	38-48%
Summer	Onshore Wind	13%	0%	13%	0%
Summer	Offshore Wind	~30%	0%	~30%	0%
Winter	Fixed Solar	5%	0%	5%	0%
Winter	Tracking Solar	5%	0%	5%	0%
Winter	Onshore Wind	33%	15-17%	33%	15-17%
Winter	Offshore Wind	60%	13%	60%	13%
Light Load	Fixed Solar	0%	21-32%	0%	21-32%
Light Load	Tracking Solar	0%	22-30%	0%	22-30%
Light Load	Onshore Wind	40%	5-8%	40%	5-8%
Light Load	Offshore Wind	60%	6-7%	60%	6-7%

* Existing values are same as base case dispatch since Helpers are not adjusted

** Proposed values vary based on which region resource is located in

Red Font = CIR MW

RTEP Baseline Testing

- Compared potential reliability violations of status quo and proposed generator deliverability procedures
  - 2026 RTEP Summer
  - 2026 RTEP Winter
  - 2026 RTEP Light Load
- Altogether there 15 new reliability violations identified with a cost estimate to fix of $185M
  - Eight overloads in Dominion: $94M
  - Three overloads in AEP: $39.5M
  - Three overloads in DPL: $43M
  - One overload in BGE: $8.5M

RTEP Baseline Testing: Identified Overloads

Fr Bus	Name	To Bus	Name	CKT	KVs	Areas	Test	Contingency	Upgrade Cost ($M)	Bound in Ops?
243009	05FRMNT	243008	05FREMCT	1	138/138	AEP	Summer	breaker	1.5	Y
314623	3WITAKRS	313854	3CONSLDL	1	115/115	Dominion	Summer	single	7	N
313854	3CONSLDL	314554	3BTLEBRO	1	115/115	Dominion	Summer	single		N
243026	05KAMMER13	246067	05NATRIUM34	1	138/138	AEP	Summer	single	28	Y
242933	05RPMONE	246929	05MADDOX	1	345/345	AEP	Summer	breaker	10	N
208069	PPL-BGE TIE	220964	GRACETON	1	230/230	BGE/PPL	Winter	tower	8.5	Y
314666	3ALTVSTA	314667	4ALTVSTA	2	115/138	Dominion	Light Load	single	6	N
231130	CECIL138	231124	GLASGOW	1	138/138	DPL	Light Load	breaker	24	N
314666	3ALTVSTA	314667	4ALTVSTA	1	115/138	Dominion	Light Load	single	6	N
313271	3TRANSCO TAP	313783	3WALNUT CRK	1	115/115	Dominion	Light Load	single	25	Y
231007	CECIL	231130	CECIL138	1	230/138	DPL	Light Load	breaker	11	N
213519	CONOWG01	231006	COLOR_PE	1	230/230	PECO/DPL	Light Load	breaker	8	N
314747	6BREMO	314744	3BREMO	1	230/115	Dominion	Light Load	single	40	Y
314747	6BREMO	313867	6BREMODIST	1	230/230	Dominion	Light Load	single	10	Y
313867	6BREMODIST	313707	6FORK UNION	1	230/230	Dominion	Light Load	single		Y

RTEP Baseline Testing

- Summer: Five reliability issues identified with a cost estimate to fix of $46.5M
  - Two reliability issues caused by higher wind and solar deliverability levels for a total cost of $7M
  - Three reliability issues caused by the block dispatch approach and low wind and solar levels on the receiving end of the constraint for a total of $39.5M
- Winter: One reliability issue identified with a cost estimate to fix of $8.5M, caused by the block dispatch approach.
- Light Load: Nine reliability issues identified for $130M
  - Two reliability issues caused by higher wind and solar deliverability levels for a total of $12M
  - Eight reliability issues caused by the block dispatch approach for a total of $118M

Queue Scenario Using CPs

- Using Impact Study Base Case (2024 RTEP Light Load & Summer) for AG1 queue
- Applying commercial probability forecast for IA Stage to reduce each queue unit's maximum output.
  - Example: 100 MW unit in the Impact Study stage has an 18% chance of reaching commercial operation so it is modelled as an 18 MW unit.

IA Stage	Commercial Probability
ISA	80%
Facilities	57%
Impact	18%

- AG1 Queue 2024 RTEP Summer & Light Load

- For the summer period there are a comparable number of overloads with the status quo
  - Number of single contingency violations went up considerably
  - Number of common mode contingency went down considerably
- For the light load period there is a substantial increase in the number of overloads compared to the status quo driven mainly by increase solar testing requirements

Queue Scenario Using Commercial Probabilities: Summer Peak

- The number of violations is comparable between the status quo and proposal.
- The number of single contingency violations went up and the number of common mode outage violations went down primarily because of the change in the deliverability levels

# Summer Overloads	Status Quo	Proposal
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Total	360	334

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Summer	Offshore Wind	~30%	68-73%	100%	68-73%

*Proposed values vary based on which region resource is located in

Red Font = CIR MW used as deliverability requirement

Queue Scenario Using CPs: Summer Violation Comparison

Violations Under Status Quo

kV	PJM East	PJM West	PJM South	TOTAL
765	0	3	0	**3**
500	3	0	17	**20**
345	0	77	0	**77**
230	44	2	70	**116**
161	0	0	0	**0**
138	10	34	2	**46**
115	27	0	18	**45**
69	12	5	0	**17**
765/345	0	8	0	**8**
500/230	3	0	4	**7**
345/230	2	0	0	**2**
345/138	0	6	0	**6**
230/115	4	0	9	**13**
115/69	0	0	0	**0**
TOTAL	**105**	**135**	**120**	**360**

Violations Under Proposal

kV	PJM East	PJM West	PJM South	TOTAL
765	0	6	0	**6**
500	7	0	25	**32**
345	1	75	0	**76**
230	25	0	95	**120**
161	0	2	0	**2**
138	1	24	0	**25**
115	4	0	28	**32**
69	10	6	1	**17**
765/345	0	4	0	**4**
500/230	4	0	6	**10**
345/230	0	0	0	**0**
345/138	0	3	0	**3**
230/115	1	0	3	**4**
115/69	0	3	0	**3**
TOTAL	**53**	**123**	**158**	**334**

Queue Scenario Using CPs: Light Load

- Overloads primarily driven by higher deliverability requirements for solar
- Status quo light load considers nighttime only
- Staff running various sensitivities

# Light Load Overloads	Status Quo	Proposal
Single Contingency	38	114
Common Mode Outage	8	48
Total	46	162

		Generator Deliverability Harmer Ramping			
		Single Contingency		Common Mode Outage	
Period	Resource Type	Existing	Proposed*	Existing	Proposed*
Light Load	Fixed Solar	0%	78-87%	0%	78-87%
Light Load	Tracking Solar	0%	82-86%	0%	82-86%
Light Load	Onshore Wind	80%	66-80%	80%	66-80%
Light Load	Offshore Wind	80%	90-93%	80%	90-93%

* Proposed values vary based on which region resource is located in

Queue Scenario Using CPs: Light Load Violation Comparison

Violations Under Status Quo

kV	PJM East	PJM West	PJM South	TOTAL
765	1	0	0	**1**
500	0	0	0	**0**
345	0	27	0	**27**
230	0	0	0	**0**
138	0	10	0	**10**
115	5	0	0	**5**
69	0	0	0	**0**
765/345	0	2	0	**2**
500/230	0	0	0	**0**
345/138	0	0	0	**0**
230/115	1	0	0	**1**
138/115	0	0	0	**0**
138/69	0	0	0	**0**
TOTAL	**7**	**39**	**0**	**46**

Violations Under Proposal

kV	PJM East	PJM West	PJM South	TOTAL
765	0	0	0	**0**
500	1	0	0	**1**
345	0	25	0	**25**
230	14	0	50	**64**
138	0	15	1	**16**
115	5	0	24	**29**
69	3	2	2	**7**
765/345	0	4	0	**4**
500/230	1	0	3	**4**
345/138	0	1	0	**1**
230/115	0	0	7	**7**
138/115	0	1	2	**3**
138/69	0	0	1	**1**
TOTAL	**24**	**48**	**90**	**162**