Load Management and PRD Performance Proposed Solution

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Considerations

- Customer choices – is it worth it to curtail? If yes, should it be through the wholesale market or self-directed peak saving (PLC)
  - PLC typically based on 5 summer CP days
  - Customer (or their consultant) must forecast peak days – potentially need to curtail ~10 summer days for 3 hours a day.
- Minimize the timing between the event and the incentive and/or penalty and associated billing.
- Performance compliance aggregation helps diversify risk across the dispatched customers

PAI event (Registrations dispatched by PJM)

PAI penalty
(~$2,300 MWh, RTO, 27/28
Stop-loss 1.5 BRA LDA price)

+ PAI Bonus
+ Energy $ (strike price)
+Potential energy cost reduction
(depends on retail rate)
+ No Test penalties

Conservative estimated incentive
$3,725 MWh = $2,300 (avoided penalty) + $1,425 (short lead strike price)

Non-PAI event (Registrations dispatched by PJM)

+ Energy $ (strike price)

+ Potential energy cost reduction (depends on retail rate)

+Option to substitute event performance for test performance

Conservative estimated incentive
$1,425 MWh (short lead strike price) or ~62% less than a PAI event

Total Capacity Revenue ($/MWh) based on capacity prices and dispatch hours

	ELCC		92%										
		Dispatch Hours											
		0	5	10	20	30	40	50	60	70	80	90	100
Price ($/ MW-day UCAP)	$50	$16,790	$3,358	$1,679	$840	$560	$420	$336	$280	$240	$210	$187	$168
	$100	$33,580	$6,716	$3,358	$1,679	$1,119	$840	$672	$560	$480	$420	$373	$336
	$150	$50,370	$10,074	$5,037	$2,519	$1,679	$1,259	$1,007	$840	$720	$630	$560	$504
	$200	$67,160	$13,432	$6,716	$3,358	$2,239	$1,679	$1,343	$1,119	$959	$840	$746	$672
	$250	$83,950	$16,790	$8,395	$4,198	$2,798	$2,099	$1,679	$1,399	$1,199	$1,049	$933	$840
	$300	$100,740	$20,148	$10,074	$5,037	$3,358	$2,519	$2,015	$1,679	$1,439	$1,259	$1,119	$1,007
	$350	$117,530	$23,506	$11,753	$5,877	$3,918	$2,938	$2,351	$1,959	$1,679	$1,469	$1,306	$1,175
	$400	$134,320	$26,864	$13,432	$6,716	$4,477	$3,358	$2,686	$2,239	$1,919	$1,679	$1,492	$1,343

Estimated Customer Capacity Revenue ($/MWh) based on capacity prices and dispatch hours to reduce capacity cost - low case

	Customer share of savings				50%								
		Dispatch Hours											
		0	5	10	20	30	40	50	60	70	80	90	100
Price ($/ MW-day UCAP)	$50	$8,395	$1,679	$840	$420	$280	$210	$168	$140	$120	$105	$93	$84
	$100	$16,790	$3,358	$1,679	$840	$560	$420	$336	$280	$240	$210	$187	$168
	$150	$25,185	$5,037	$2,519	$1,259	$840	$630	$504	$420	$360	$315	$280	$252
	$200	$33,580	$6,716	$3,358	$1,679	$1,119	$840	$672	$560	$480	$420	$373	$336
	$250	$41,975	$8,395	$4,198	$2,099	$1,399	$1,049	$840	$700	$600	$525	$466	$420
	$300	$50,370	$10,074	$5,037	$2,519	$1,679	$1,259	$1,007	$840	$720	$630	$560	$504
	$350	$58,765	$11,753	$5,877	$2,938	$1,959	$1,469	$1,175	$979	$840	$735	$653	$588
	$400	$67,160	$13,432	$6,716	$3,358	$2,239	$1,679	$1,343	$1,119	$959	$840	$746	$672

In the low case, a customer may reduce 50% of their capacity cost which equates to $1,399 MWh if the Capacity Price is $250 MW-day and they successfully reduce load for 30 hours

Estimated Customer Capacity Revenue ($/MWh) based on capacity prices and dispatch hours to reduce capacity cost - high case

	Customer share of savings				90%								
		Dispatch Hours											
		0	5	10	20	30	40	50	60	70	80	90	100
Price ($/ MW-day UCAP)	**$50**	**$15,111**	$3,022	$1,511	$756	$504	$378	$302	$252	$216	$189	$168	$151
	$100	**$30,222**	$6,044	$3,022	$1,511	$1,007	$756	$604	$504	$432	$378	$336	$302
	$150	**$45,333**	$9,067	$4,533	$2,267	$1,511	$1,133	$907	$756	$648	$567	$504	$453
	$200	**$60,444**	$12,089	$6,044	$3,022	$2,015	$1,511	$1,209	$1,007	$863	$756	$672	$604
	$250	**$75,555**	$15,111	$7,556	$3,778	$2,519	$1,889	$1,511	$1,259	$1,079	$944	$840	$756
	$300	**$90,666**	$18,133	$9,067	$4,533	$3,022	$2,267	$1,813	$1,511	$1,295	$1,133	$1,007	$907
	$350	**$105,777**	$21,155	$10,578	$5,289	$3,526	$2,644	$2,116	$1,763	$1,511	$1,322	$1,175	$1,058
	$400	**$120,888**	$24,178	$12,089	$6,044	$4,030	$3,022	$2,418	$2,015	$1,727	$1,511	$1,343	$1,209

In the high case, a customer may reduce 90% of their capacity cost which equates to $2,519 MWh if the Capacity Price is $250 MW-day and they successfully reduce load for 30 hours

Proposed Change – an event is an event

- All Load Mgt/PRD events are subject to a penalty and not required to test when dispatched. Penalty Rate and penalty $ allocation different for non-PAI event.
  - Non-PAI event penalty rate = 50% * PAI penalty rate (~$1,150 MWh based on 27/28 RTO)
  - Non-PAI and PAI events subject to same aggregation rules for compliance
  - PAI + Non-PAI penalty subject to existing PAI Stop Loss rules
  - Penalty $ collected allocated on a prorata basis to load based on existing test penalty allocation process.

Make new rules effective for the 28/29 DY

Proposed non-PAI event changes (Registrations dispatched by PJM)

Non-PAI penalty

(~$1,150 MWh, RTO, 27/28

Stop-loss 1.5 BRA LDA price for PAI + Non-PAI events)

+ PAI Bonus

+ Energy $ (strike price)

+Potential energy cost reduction (depends on retail rate)

+ No Test penalties

Conservative estimated incentive
$2,575 MWh = $1,150 (avoided penalty) + $1,425 (short lead strike price)

High level comparison

Item	Gen	DR
Capacity Market	Must offer requirement subject to price mitigation (e.g.: MOPR/MSOC)	Price based offers
Capacity accreditation	ICAP * class ELCC * Performance adjustment factor, CIR cap	Summer and winter ICAP * class ELCC
Energy Market	Cost based must offer requirement based on ICAP. Ability to request outages	Dispatched when expected to be short on reserves, Price based energy offers. Outages in very limited circumstances.
“Non-PAI” compliance impact	No revenue from Energy market when prices are high, future UCAP derate, imbalance penalty (BOR, DA vs RT delta)	Continue with primary business objective ($) but forgo energy revenue incentive to offset cost
Compliance	UCAP by resource/unit	ICAP, ability to aggregate performance (RTO or MAD)

Market rule differences are by design
DR only required to reduce load when needed but expected to fully respond

Proposed non-performance charge - example

		Load Reduction							
Location	**MW (ICAP)**	**HE12**	**HE13**	**HE14**	**HE15**	**HE16**	**HE17**	**HE18**	**HE19**
A	1.0	1.2	1.0	0.8	1.0	0.8	0.7	0.7	0.6
B	2.0	0.0	1.2	2.0	2.0	2.2	2.0	2.0	1.5
C	3.0	2.0	3.0	3.5	3.0	3.1	0.0	0.0	0.0
Total	**6.0**	**3.2**	**5.2**	**6.3**	**6.0**	**6.1**	**2.7**	**2.7**	**2.1**
Avg Reduction	4.3								
Performance	71%								
Shortfall MW		2.8	0.8	-0.3	0.0	-0.1	3.3	3.3	3.9
PAI penalty rate ($/mwh)	$2,300								
Non-PAI penalty rate ($/mwh)	$1,150								
		$3,220	$920	$0	$0	$0	$3,795	$3,795	$4,485
Total Penalty	**$16,215**								
ELCC	0.92								
UCAP commitment	5.5								
UCAP Price	$250								
UCAP Revenue	$503,700								
Penalty/Revenue	3%								

PJM considerations

- DR Performance adjustment issue
  - Limited performance hours
  - DR measured based on ICAP – Gen performance adjustment factor relative to UCAP (class average ELCC)
  - Aggregation: CSP > Resource > Customer
  - CSP vs retail customer
- Pull DR from PAI structure and leverage pre-CP DR non-performance charge rules
  - Penalty rate a function of # events and existing annual daily deficient penalty rate (weighted average revenue rate * 1.2 or +$20 MW day UCAP) * 365
    - 2 event days than penalty rate is 50% of annual penalty rate, 3 event days then 33.3% of annual penalty rate, etc.
  - Big change, several details to work out – resources did perform, just need to improve performance.

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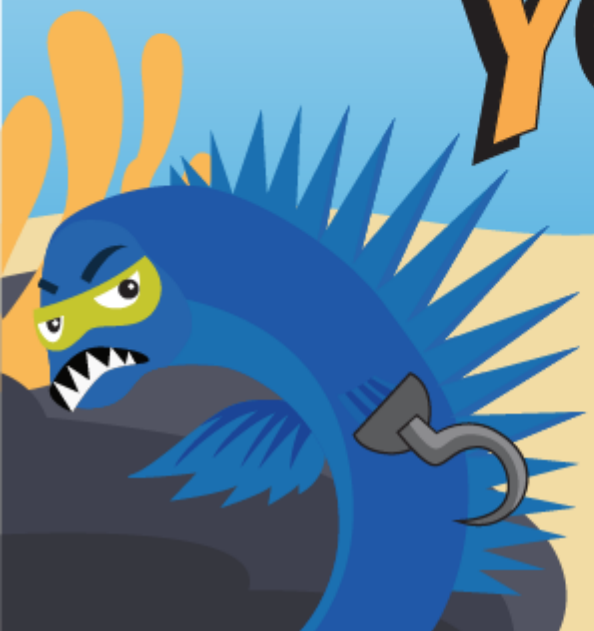

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