Powerex Response to Brattle Paper On Day-Ahead Markets

As western utilities, public interest organizations, state regulators and other western stakeholders continue to evaluate SPP's Markets+ and the California ISO's EDAM, regional dialogue has been increasingly focused on the key differences in the governance and initial market designs of these two markets. Supporters of Markets+ have been sharing a series of Issue Alerts explaining how Markets+ will differ substantially from EDAM in several key market design areas, and how these differences can be expected to result in important economic, reliability and environmental consequences for market participants and electricity consumers across the west.

A recent paper[1] by The Brattle Group, sponsored by PacifiCorp (which has committed to join EDAM), offers a very different perspective on several of the market design differences between Markets+ and EDAM. The open sharing of different ideas and perspectives that increases the understanding of the two day-ahead market alternatives and their implications for western entities, their regulators, and consumers is beneficial to the regional dialogue. Unfortunately, the Brattle paper frustrates this objective, as it:

1) contains several material misstatements of facts related to the market designs of both markets;
2) repeatedly overlooks readily available evidence that is directly contrary to its conclusions; and
3) mischaracterizes the evidence that it does present.

The failure of the Brattle paper to provide a credible and fact-based examination of the market design differences is clearly evident in its discussion of fast-start pricing. Powerex has followed the fast-start pricing issue closely for several years, and understands its regulatory history at FERC, its application in organized markets, and the strong opposition to it by the California ISO and its internal market monitor. In 2021, Powerex, together with the Public Power Council, engaged EnergyGPS to conduct a detailed analysis of the impact of this pricing issue to consumers in different parts of the West. ***Given its familiarity and involvement in this issue, Powerex is issuing this paper to provide a brief background on fast-start pricing and to highlight several key areas of concern with the Brattle paper's analysis and conclusions.***

[1] The Proposed Day-Ahead Markets in the WECC (brattle.com)

Background On Fast Start Pricing

In organized electricity markets, the market price is generally set based on what it would cost to produce one more unit of energy (marginal cost pricing). All supply and all demand then receives or pays this market price, including imports and exports across state boundaries.[2] Sometimes the best way to meet the need for "one more unit of energy" is to start up a natural gas "peaking unit," that runs at or close to full output once it is started (*i.e.*, it represents a large block of electricity, such as 100 MW, that must be dispatched in its entirety, incurring both start-up costs and production fuel costs). In organized markets with fast-start pricing, special pricing logic is applied to ensure that the cost of starting and running these "block loaded" units is permitted to set the market price when they are determined to be providing the generation supply at the margin. But in markets without fast-start pricing, the market price can often be well below the cost of running these peaking units (since their costs are excluded), resulting in an artificially low wholesale market price[3]. Importantly, this lowers the amount paid to local generators and to imports from neighboring jurisdictions, including imports of electricity from solar, wind, hydro and other resource types. Avoiding the adoption of fast-start pricing therefore largely benefits utilities (and their ratepayers) in jurisdictions like California that typically import electricity during the hours of the day that gas peaking units are frequently used, while harming suppliers (and their ratepayers) in jurisdictions that typically export electricity during those same hours.

FERC has clearly endorsed the efficacy and beneficial impact of fast-start pricing, stating that "given the unique operating characteristics of fast-start resources, their commitment costs, *i.e.*, start-up and no-load costs, should be viewed as marginal costs and, as such, should be included in prices."[4] Accordingly, in 2016, FERC proposed to require all organized markets to implement fast-start pricing.[5] The California ISO strongly opposed this proposal, as did its internal market monitor, and FERC ultimately did not make fast-start pricing a blanket requirement for all organized markets. Instead, FERC went on to individually require three eastern organized markets—but not the California ISO—to adopt fast-start pricing. But even this was opposed by the California ISO's internal market monitor, which notably intervened at FERC to oppose the implementation of fast-start pricing in these other markets. Such opposition aligns with California's own interests, since the state has historically been a large importer of electricity from both Northwest and Southwest utilities in those hours that gas peakers are running.

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[2] The market price can differ by location, since providing electricity at one location may require a different combination of generation than providing electricity at a different location.

[3] As a result of a lower market clearing price, the fast start resource may be eligible to recover its costs through make-whole payments (*i.e.*, "uplift") typically funded by other market participants.

[4] *See* FERC Notice of Proposed Rulemaking in Docket No. RM17-3, Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, (December 2016), at 51.

[5] *Id.*

A comprehensive analysis performed by EnergyGPS in 2021, co-sponsored by Public Power Council and Powerex, highlights the large transfer of value between ratepayers in these western sub-regions as a result of the California ISO's market design decision. The analysis estimates that California entities are saving more than $1 billion dollars per year by not adopting fast-start pricing, with roughly $400 million of those annual savings coming from under-compensating Northwest and Southwest utilities for wholesale electricity imports, which ultimately raises retail electricity rates outside of California. The entire report can be found here.

Today, the California ISO remains the only FERC-jurisdictional organized market that lacks fast-start pricing. EDAM and EIM, as extensions of the California ISO's legacy market design, will also lack fast-start pricing unless and until the California ISO changes its mind and adopts it. Markets+, however, will include fast-start pricing from the outset.

The Brattle Paper's Discussion Of Fast Start Pricing

The Brattle paper takes the position that this market design difference is inconsequential, stating that:

Some stakeholders have presented analyses suggesting that FSP has a substantial impact on market prices … [but] evidence from several U.S. markets … indicates that FSP has a very minimal impact on market prices [and] impacts relatively few hours[.][6]

Numerous aspects of the Brattle paper's fast start pricing analysis are either factually wrong or materially misleading.

For instance, the Brattle paper seeks to draw support from experience in MISO, observing that "FSP affected only around 7.2% of real-time clearing intervals, impacting market-wide real-time prices by an average of only $0.03/MWh ***in 2015***. … [and] FSP affected only around 7.7% of real-time clearing intervals, impacting market-wide real-time prices by an average of $0.01/MWh ***in 2016***."[7]

Brattle does not explain why it chose to only present MISO data from 2015 and 2016, particularly when several additional years' worth of evidence is readily available online.[8] This is a glaring omission, as later reports paint a very different picture. In 2021, the MISO Independent Market Monitor explained that while the initial effect of fast-start pricing was very small (when fast-start pricing was a new market design feature), MISO subsequently made important changes to how it applies fast-start pricing that "have significantly improved real-time price formation in MISO."[9] While Brattle has chosen to use outdated reports to claim that the "frequency and magnitude of the price impacts of [fast-start pricing] were very small,"[10] a full

[6] Brattle, at 9.

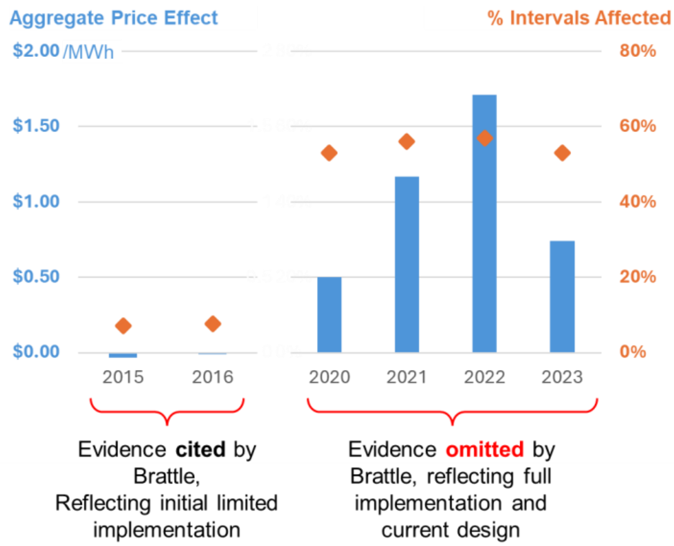
[7] Brattle, at 10-11. (Emphasis added)

[8] Brattle was aware of these later reports, and cites them when discussing other topics. *See* Brattle at footnote 32 (citing the 2021 MISO State of the Market Report).

[9] Potomac Economics, MISO State of the Market Report 2021, at 41.

[10] Brattle, at 10.

review of the readily available MISO reports show the exact opposite, and that the average impact is not $0.01/MWh or $0.03/MWh, ***but 50 to 100 times higher than that***:

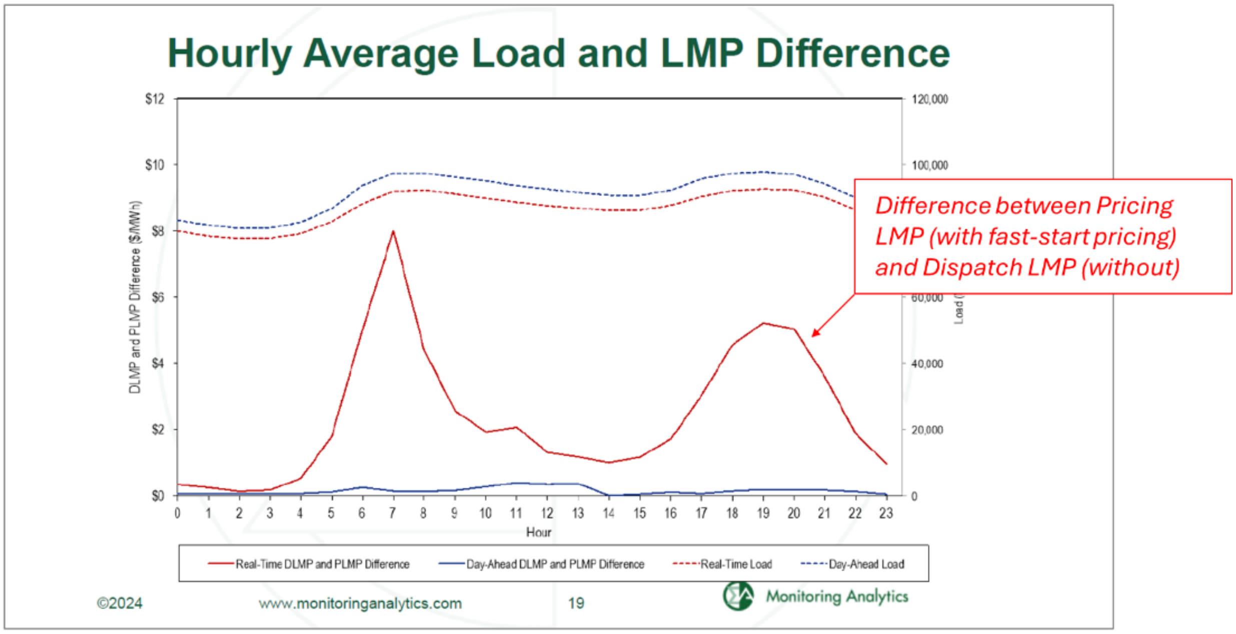


> Initially, the online component of ELMP had a very small effect on prices, partly because of the limited set of units that were qualified as FSRs and eligible to set ELMPs. MISO implemented changes in 2017 and 2019 to expand the set of eligible FSRs, which has improved the performance of ELMP in setting prices.
>
> MISO implemented another of our recommendations in September 2021 to relax the down ramp rate limit on FSRs dispatched at their economic minimums. Together, these changes have significantly improved real-time price formation in MISO.
>
> \- 2021 State of the Market Report for the MISO Electricity Markets, at 41.

The Brattle paper also omits evidence of fast-start pricing in PJM. In PJM, like in MISO over the last several years, fast-start pricing has resulted in moderately higher market prices on average.[11] But the PJM analysis provides a more granular view of the price impacts during certain hours of the day, highlighting the increased importance of fast-start pricing during the morning and evening demand peaks.[12]

[11] *See, e.g.,* Monitoring Analytics, Market Monitor Report, MC Webinar 05.20.2024 (Revised 05.31.2024), at 8-19.

[12] Monitoring Analytics, Market Monitor Report, MC Webinar 05.20.2024 (Revised 05.31.2024), at 19. (Annotation added)



In the chart above, it can be seen that the average price impact in the morning and evening demand peaks ranges from about $4/MWh to $8/MWh.

The Brattle paper briefly acknowledges that, in ISO New England, "average system energy prices increased by 11%, or $2.72/MWh," but cautions "although that analysis is limited to the first eight months after FSP came into effect."[13] Brattle could easily have reviewed the annual reports for ISO New England published since then, in which its internal market monitor concludes that "fast-start pricing rules in the real-time energy market continue to have notable impacts on pricing and market costs."[14]

The Brattle paper then grossly exaggerates the findings of the analysis by EnergyGPS that was co-sponsored by Public Power Council and Powerex. The Brattle paper claims the analysis "suggests that during 2017–2020 the impact of FSP would have resulted in ***average energy price impacts*** of $15–$23/MWh[.]"[15] In fact, the report clearly states that "***[f]or the evening peak hour from 6 p.m. and 7 p.m.***, this price impact averaged nearly $15/MWh in NP15, and nearly $23/MWh in SP15." The Brattle paper takes the price impact of the single-highest hour and presents it as the price impact across all hours, which is simply false.

The complete set of price impacts found by EnergyGPS are shown below, and range from an average of around $1.3/MWh in the Southwest and Northwest regions to around $6.7/MWh in

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[13] Brattle, at 11.

[14] ISO New England, 2023 Annual Markets Report, at 80.

[15] Brattle, at 11. (Emphasis added)

SP15, which is entirely consistent with the analyses of the actual price impact of fast-start pricing in MISO, PJM and ISO New England:[16]

Results mischaracterized by Brattle
as “average energy price impacts”

		Hour Ending																							
	Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
SP15	2017	0.40	0.34	0.10	0.12	0.33	5.52	10.56	8.11	5.84	4.60	4.42	3.70	3.19	4.03	4.01	3.30	7.10	14.94	21.75	2.23	19.63	5.64	1.78	0.55	6.34
	2018	0.55	0.82	0.20	0.41	2.86	11.23	17.13	13.02	8.42	8.33	5.57	4.69	5.12	5.88	8.47	9.42	14.42	24.47	29.13	7.44	16.11	6.42	2.67	2.21	9.37
	2019	1.69	0.95	0.69	0.43	1.66	8.25	11.21	9.89	7.50	6.06	4.58	4.03	4.86	3.88	3.68	4.59	8.67	17.34	21.21	7.59	11.22	5.54	1.77	0.77	6.59
	2020	1.42	1.62	0.68	0.41	1.15	3.04	6.26	5.66	4.13	3.51	2.21	1.29	1.17	1.37	2.03	3.52	8.92	15.06	19.30	6.46	7.97	2.85	0.91	0.71	4.61
NP15	2017	0.74	0.44	0.13	0.14	0.39	3.37	6.05	3.68	2.26	1.64	1.81	1.49	2.12	1.62	1.17	1.47	6.00	13.58	19.73	6.38	9.45	3.29	0.74	0.30	4.08
	2018	0.49	0.68	0.43	0.72	1.66	5.11	6.66	5.43	2.59	0.85	1.87	2.49	1.85	2.36	1.87	2.69	5.76	11.74	15.19	1.88	7.61	2.86	0.96	0.87	3.94
	2019	0.29	0.39	0.08	0.34	0.40	3.58	5.18	4.14	2.06	1.54	0.70	1.03	1.33	1.02	0.86	1.98	4.70	11.13	12.75	9.10	5.02	1.15	0.63	0.53	2.91
	2020	0.76	0.76	0.24	0.34	0.49	2.09	3.86	2.92	1.35	0.61	0.69	0.94	1.15	0.84	0.63	1.97	5.15	10.50	12.00	7.78	3.99	1.46	0.56	0.32	2.56
Southwest	2017	0.61	0.64	0.79	0.44	0.44	1.03	3.21	5.83	8.29	6.49	3.48	2.64	1.79	1.83	2.11	2.10	2.29	2.74	4.27	5.39	5.34	4.96	2.98	1.41	2.96
	2018	0.28	0.19	0.13	0.05	0.15	0.63	1.47	2.50	2.91	2.18	1.49	0.69	0.84	0.81	1.05	1.07	1.20	1.55	1.73	1.79	1.67	1.45	0.73	0.32	1.12
	2019	0.30	0.05	0.05	0.02	0.03	0.16	0.16	0.47	1.55	1.21	0.77	0.53	0.47	0.52	0.44	0.29	0.42	0.53	0.62	0.62	0.74	0.20	0.01	0.12	0.43
	2020	0.15	0.16	0.14	0.16	0.16	0.32	0.78	0.91	1.88	2.25	1.66	1.15	1.33	0.73	0.76	0.57	0.63	0.85	0.83	0.80	0.55	0.74	0.22	0.19	0.75
Pacific Northwest	2017	0.78	0.75	0.65	0.96	0.71	1.12	2.63	3.20	4.59	4.05	2.54	1.70	1.72	1.38	1.10	1.84	1.76	2.37	2.47	2.99	2.48	2.64	1.79	1.67	2.00
	2018	0.91	0.68	0.73	0.71	0.96	1.99	1.69	3.74	2.86	2.86	2.44	1.97	2.15	1.70	1.68	3.69	1.93	1.91	2.27	1.73	1.20	1.75	1.29	1.12	1.83
	2019	0.14	0.38	0.19	0.31	0.33	0.33	0.49	0.64	0.96	0.93	0.44	0.35	0.33	0.43	0.38	0.33	2.37	2.01	2.30	0.86	0.55	0.41	0.19	0.16	0.66
	2020	0.30	0.45	0.12	0.32	0.17	0.17	0.29	0.61	0.78	0.86	0.99	1.28	0.85	0.77	0.70	0.58	0.81	1.10	1.58	1.10	0.73	0.28	0.10	0.04	0.62

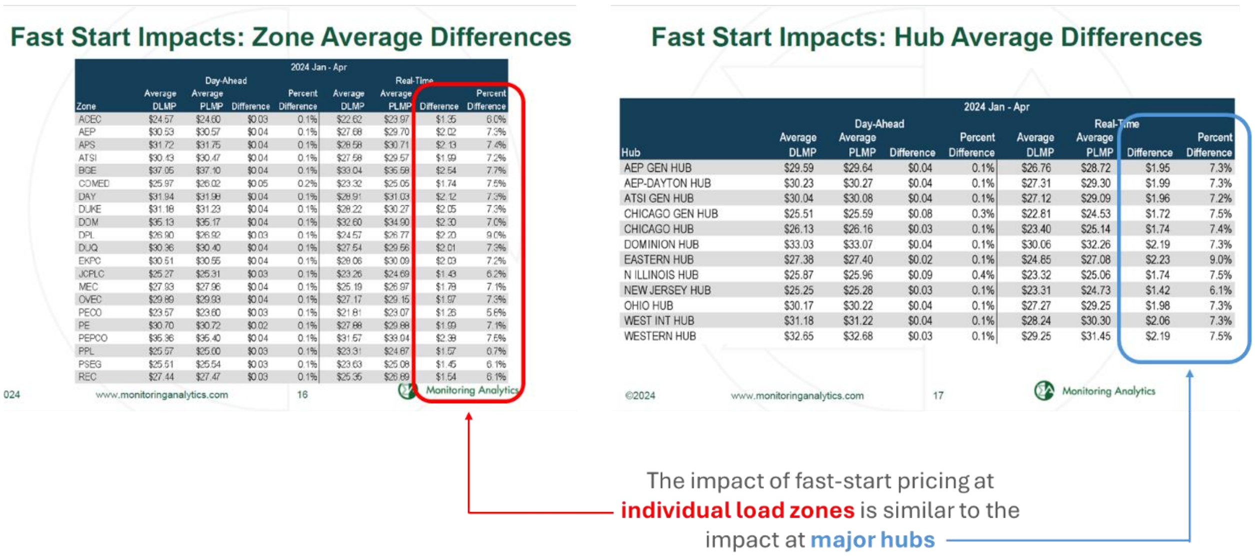
A closer look at the results of EnergyGPS’s analysis reveals that it finds fast-start pricing has a significant impact in some hours and in some seasons, but has little or no impact in other hours or times of the year. This is highly consistent with the patterns identified in PJM by its market monitor.

The Brattle paper further faults the EnergyGPS study because it “does not differentiate between locational marginal prices (LMPs) at individual nodes and averaged hub prices,” and claiming that the “averaging involved in computing hub prices would dilute the impacts of localized fast start pricing.”[17] But the Brattle paper’s criticism is factually unfounded. Not only did EnergyGPS carefully consider and make adjustments to address fast-start pricing impacts that are localized in its analysis at hub locations, recent reports by PJM’s market monitor show that the average impact of fast-start pricing at specific load locations is virtually the same as the average impact on hub prices:[18]

[16] SPP implemented fast-start pricing in 2022, but the annual reports of its Market Monitoring Unit do not contain direct analyses of the impact on electricity prices. NYISO has used fast-start pricing for many years, but the annual reports prepared by its market monitor also do not contain analyses of the impact of this methodology.

[17] Brattle, at 12.

[18] Monitoring Analytics, Market Monitor Report, MC Webinar 05.20.2024 (Revised 05.31.2024), at 16-17 (Annotation added)



	2024 Jan - Apr							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$24.57	$24.60	$0.03	0.1%	$22.62	$23.97	$1.35	6.0%
AEP	$30.53	$30.57	$0.04	0.1%	$27.68	$29.70	$2.02	7.3%
APS	$31.72	$31.75	$0.04	0.1%	$28.58	$30.71	$2.13	7.4%
ATSI	$30.43	$30.47	$0.04	0.1%	$27.58	$29.57	$1.99	7.2%
BGE	$37.05	$37.10	$0.04	0.1%	$33.04	$35.58	$2.54	7.7%
COMED	$25.97	$26.02	$0.05	0.2%	$23.32	$25.05	$1.74	7.5%
DAY	$31.94	$31.98	$0.04	0.1%	$28.91	$31.03	$2.12	7.3%
DUKE	$31.18	$31.23	$0.04	0.1%	$28.22	$30.27	$2.05	7.3%
DOM	$35.13	$35.17	$0.04	0.1%	$32.60	$34.90	$2.30	7.0%
DPL	$26.90	$26.92	$0.03	0.1%	$24.57	$26.77	$2.20	9.0%
DUQ	$30.36	$30.40	$0.04	0.1%	$27.54	$29.56	$2.01	7.3%
EKPC	$30.51	$30.55	$0.04	0.1%	$28.06	$30.09	$2.03	7.2%
JCPLC	$25.27	$25.31	$0.03	0.1%	$23.26	$24.69	$1.43	6.2%
MEC	$27.93	$27.96	$0.04	0.1%	$25.19	$26.97	$1.78	7.1%
OVEC	$29.89	$29.93	$0.04	0.1%	$27.17	$29.15	$1.97	7.3%
PECO	$23.57	$23.60	$0.03	0.1%	$21.81	$23.07	$1.26	5.8%
PE	$30.70	$30.72	$0.02	0.1%	$27.88	$29.88	$1.99	7.1%
PEPCO	$35.36	$35.40	$0.04	0.1%	$31.57	$33.94	$2.38	7.5%
PPL	$25.57	$25.60	$0.03	0.1%	$23.31	$24.87	$1.57	6.7%
PSEG	$25.51	$25.54	$0.03	0.1%	$23.63	$25.08	$1.45	6.1%
REC	$27.44	$27.47	$0.03	0.1%	$25.35	$26.89	$1.54	6.1%

	2024 Jan - Apr							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$29.59	$29.64	$0.04	0.1%	$26.76	$28.72	$1.95	7.3%
AEP-DAYTON HUB	$30.23	$30.27	$0.04	0.1%	$27.31	$29.30	$1.99	7.3%
ATSI GEN HUB	$30.04	$30.08	$0.04	0.1%	$27.12	$29.09	$1.96	7.2%
CHICAGO GEN HUB	$25.51	$25.59	$0.08	0.3%	$22.81	$24.53	$1.72	7.5%
CHICAGO HUB	$26.13	$26.16	$0.03	0.1%	$23.40	$25.14	$1.74	7.4%
DOMINION HUB	$33.03	$33.07	$0.04	0.1%	$30.06	$32.26	$2.19	7.3%
EASTERN HUB	$27.38	$27.40	$0.02	0.1%	$24.85	$27.08	$2.23	9.0%
N ILLINOIS HUB	$25.87	$25.96	$0.09	0.4%	$23.32	$25.06	$1.74	7.5%
NEW JERSEY HUB	$25.25	$25.28	$0.03	0.1%	$23.31	$24.73	$1.42	6.1%
OHIO HUB	$30.17	$30.22	$0.04	0.1%	$27.27	$29.25	$1.98	7.3%
WEST INT HUB	$31.18	$31.22	$0.04	0.1%	$28.24	$30.30	$2.06	7.3%
WESTERN HUB	$32.65	$32.68	$0.03	0.1%	$29.25	$31.45	$2.19	7.5%

Finally, the Brattle paper criticizes the EnergyGPS analysis because it "did not simulate a counterfactual market commitment and dispatch solution." But Brattle is either unaware, or ignores, that the very design of fast-start pricing is that it "is a price-setting engine that does not affect the dispatch."[19] The "counterfactual" analysis the Brattle paper calls for is not only unnecessary, it would be entirely wrong since fast-start pricing is specifically designed to avoid affecting the market commitment and dispatch solution.

[19] *See* Potomac Economics, MISO State of the Market Report 2023 – Analytic Appendix, at 42.

<u>Further Misrepresentations And Errors In The Brattle Paper's Treatment of Other Market Design Issues</u>

The Brattle paper's mischaracterizations and selective omission of relevant information extends to its discussion of other key market design differences between Markets+ and EDAM.

GHG Pricing Mechanisms

The Brattle paper incorrectly describes the California ISO's GHG attribution approach, using an example. Specifically, the discussion and the example overlook a key design element of ***the California ISO's GHG mechanism that, in practice, allows clean generation located outside California and that serves demand outside of California to nevertheless be incorrectly labeled as a clean import serving load inside California.*** This design loophole has resulted in extensive leakage in the Western EIM, where large amounts of electricity have been dispatched from high-emitting fossil fueled generation resources outside of California, but where the resulting imports were claimed to be from clean generation resources whose output did not increase in the EIM. This problem was extensively analyzed and discussed in a 2022 report by Powerex. Given that Brattle has conducted multiple production cost studies modeling the operation of EDAM, its inaccurate understanding of how that market's GHG mechanism works raises broad concerns about the accuracy of its analyses and conclusions.

Congestion Revenue Allocation

The Brattle paper recognizes that, in Markets+, congestion revenues are directly allocated to the transmission customers that have invested in transmission rights on the congested transmission facilities, whereas EDAM leaves the allocation of congestion revenues to each transmission provider. However, the Brattle paper predicts that "while the EDAM approach does not explicitly require BAAs to compensate third-party transmission customers, EDAM BAAs are likely to do so." The Brattle paper therefore concludes that "the two approaches may not end up materially different."[20]

There is absolutely no support for the Brattle paper's sweeping assumption that each of the transmission providers joining EDAM will individually adopt the very congestion revenue allocation framework that is directly applied across the entire Markets+ footprint. In fact, PacifiCorp—the sponsor of the Brattle paper and the first EDAM transmission provider to propose how it will allocate congestion revenue—has not proposed to adopt that approach, and has instead proposed to spread the congestion revenues it receives in EDAM uniformly across all of its demand, and *not* to the customers that have invested in transmission rights on the constrained facilities. This directly contradicts the generic expectation behind the Brattle paper's conclusion.

The Brattle paper also ignores the tremendous ability for a market operator to impact the precise locations that appear to be congested, and therefore which transmission providers will receive congestion revenues in the first instance. This influence was readily apparent during

[20] Brattle, at 26-27.

the winter weather event of last January, where the California ISO collected congestion revenue on exports using the jointly funded Pacific AC Intertie totaling ***over $100 million in just five days***. These congestion revenues were allocated to the California ISO's customers under the California ISO's rules, even though the transmission facilities are jointly funded and jointly operated with Bonneville Power Administration and other transmission providers, and the actual physical congestion appears to have occurred in Oregon.[21]

Flow-Based vs. Contract Path-Based Optimization

The Brattle paper asserts that "[s]ome stakeholders have suggested that Markets+ will rely ***solely*** on flow-based optimization, while the EDAM will continue the WEIM's practice of relying on both flow-based and contract path-based optimization."[22] This is incorrect. Both markets will need to apply contract-path limits for transmission rights that are used outside of the respective organized market. But the actual distinction that has been pointed out is that in EDAM, the California ISO will also apply contract-path limits to EDAM transfers between balancing areas participating in the EDAM, just as it applies contract-path limits for EIM transfers between entities in the EIM. In contrast, Markets+ will limit transfers between balancing areas participating in Markets+ based on physical flow-based limits, enabling more efficient use of the transmission system.

Conclusion

Western entities, regulators and consumers deserve the benefit of an open exchange of views regarding the important differences in market design between Markets+ and EDAM and the potential impacts of those differences. But rather than providing accurate information and credible analysis to further a constructive dialogue in the region, the Brattle paper puts forward erroneous conclusions by misrepresenting and selectively omitting opposing information. The extent and the significance of this misinformation raises concerns about the assumptions inherent in other Brattle analyses comparing EDAM and Markets+.

[21] This event and the allocation of congestion rents by the California ISO were the topic of several presentations at the March 8, 2024 meeting of the Pacific Northwest Utilities Conference Committee board of directors, available here.

[22] Brattle, at 6.