UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators	**)**	**Docket No. RM21-14-000**

JOINT COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

Pursuant to the Supplemental Notice of Inquiry (NOI) issued by the Federal Energy Regulatory Commission (Commission) in the above-captioned proceeding on March 18, 2021, the undersigned Public Interest Organizations (PIOs)[1] respectfully submit the following responses to the Commission NOI on whether to revise Commission regulations that require a Regional Transmission Organization (RTO) or Independent System Operator (ISO) not to accept bids from an aggregator of retail customers (ARC) where the relevant electric retail regulatory authority (RERRA) prohibits customers' demand response (DR) to be bid into organized markets by an ARC ("DR Opt-Out Rule").[2]

I. INTRODUCTION

Most of our organizations offered comments in the Commission's rulemaking proceedings on Order No. 719 in 2008 and Order No. 719-A in 2009. PIO comments to the

[1] Environmental Law and Policy Center, Natural Resources Defense Council, Sierra Club, and Sustainable FERC Project.

[2] *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071 at P156 (Oct. 17, 2008) ("Order No. 719").

Commission in those proceedings discussed the many benefits DR resources can provide to grid operators and wholesale markets and offered the following recommendations:[3]

- Comparable treatment of all distributed resources in organized markets to increase system benefits, including greater economic efficiency, lowered costs, reduced price volatility, improved reliability, avoided transmission investments, and reduced market power;
- Explicit inclusion of energy efficiency, distributed generation and other distributed resources alongside demand response resources in Commission rules to support market participation; and
- Prohibition of market rules and policies that would prevent or inhibit aggregators of energy efficiency and distributed resources (including demand response) from full participation in all organized power markets.

The rapid expansion of and demand for flexible operation services and market products offered in organized markets over the last decade alongside growth in services and capabilities of ARCs and DR technologies demonstrate an urgent need to remove the DR Opt-Out Rule. Removing the DR Opt-Out Rule is a necessary first step to unlock the competitive and operational benefits DR resources can provide to wholesale markets where RTOs or ISOs currently limit or ban ARC participation under DR Opt-Out Rule.[4] In 2009, organized markets were far less well

[3] *See generally*, "Initial Joint Comments of Public Interest Organizations and Allied Groups," Docket Nos. RM07-19-000, AD-07-7-00 (2008).

[4] PIOs were able to confirm at least thirteen state RERRAs that limit or ban ARCs from participation in wholesale markets under the DR Opt-Out Rule: Arkansas, Iowa, Indiana, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Mississippi, North Carolina, North Dakota, South Dakota, and Wisconsin.

developed than they are today, and many notable legal, policy and technological developments have occurred (and are still ongoing) that are relevant to this NOI.

PIOs support removal of the DR Opt-Out Rule because it violates the Federal Power Act (FPA), results in unjust and unreasonable rates, and is unduly discriminatory and preferential. The DR Opt-Out Rule, as implemented in RTO and ISO tariffs, has constrained DR resource participation in wholesale markets. For example, the Midcontinent Independent System Operator (MISO) is now the geographically largest RTO in the country. Of the 15 states wholly or partly in MISO, only Illinois, Michigan, and Texas allow DR aggregations from ARCs not operating on behalf of a load serving entity (LSE) to participate in wholesale markets.[5] In the Southwest Power Pool (SPP), many RERRAs have also exercised the DR Opt-Out Rule.[6] These bans and restrictions under the DR Opt-Out Rule have led to a lack of competition, possibly resulting in increased wholesale rates and reduced efficacy of DR programs.[7]

We understand and commend the Commission's interest in fully understanding the trade-offs associated with eliminating the DR Opt-Out Rule, including any impacts on state-level programs, but as demonstrated in these comments, conclude that the wholesale market and reliability benefits of eliminating the Opt-Out far outweigh any such impacts. Accordingly, the Commission should remove the DR Opt-Out Rule and require RTOs and ISOs eliminate

[5] In Michigan, aggregators are only allowed to compete with LSEs for demand response customers in the 10% of the state subject to retail competition.

[6] Commissioner Danly includes Kansas, Oklahoma, Montana, Nebraska, and New Mexico in a list of states that have opted out, but PIOs were unable to verify the status of these states or whether RERRAs not under state jurisdiction have opted out. Danly NOI Concurrence at 1.

[7] Compl. of Voltus, Inc. Requesting Fast Track Processing, at 1–2, Docket No. EL21-12-000 (Oct. 20, 2020), Accession No. 20201020-5136 ("Voltus Complaint").

requirements that aggregators certify RERRA authority before participation in wholesale markets.

II. PIO RESPONSES TO NOI QUESTIONS

The PIOs are providing responses below to Q1 and Q3 – Q7.

A. Questions Regarding Changed Circumstances Relevant to the DR Opt-Out Rule Since Issuance of Order Nos. 719 and 719-A

Q1) To what extent have the type and capabilities of demand response technologies and aggregations available to parties seeking to participate in RTO/ISO markets changed since 2009? (Footnote omitted.)

As demonstrated in the Testimony of Paul Centolella in the Voltus, Inc. complaint to the Commission (Docket EL-21-1200)[8], significant technological developments—such as the acceleration of Advanced Metering Infrastructure--have paved the way for greater and more responsive DR participation.[9] Current data from the Energy Information Administration (EIA) show that electricity provided through advanced metering increased from 188 million to 1.9 billion MWh between 2009 and 2019.[10] As further explained by Mr. Centolella:

> Today, inexpensive embedded processors and sensors, near ubiquitous connectivity, advances in data analytics and machine learning allow intelligent systems to control industrial processes, agricultural equipment, data center operations, building environments, distributed energy resources, electric vehicle charging, and multiple devices in our homes. Intelligent systems can learn preferences and optimize the timing of electricity use in response to multiple inputs. Such inputs can include the instructions of demand response aggregators, RTO control signals, energy prices, or local grid conditions.[11]

[8] Voltus Complaint, Docket No. EL21-12-000, at P1 (filed Oct. 20, 2020) Centolella, Ex. A.

[9] Voltus Complaint, Docket No. EL21-12-000, Centolella, Ex. A.

[10] U.S. Energy Information Administration's Annual Electric Report (2019), *available at:* https://www.eia.gov/electricity/annual/pdf/epa.pdf, at tbl 1.2 ("Summary Statistics for the United States, 2008 – 2018"); *see also* FERC Staff Report, *2019 Assessment of Demand Response and Advanced Metering*, at P 13-17 (2019) (retail and wholesale demand response each ~30,000 MW in last reporting year).

[11] Voltus Complaint, Docket No. EL21-12-000, Ex. A. Centollela Testimony at 7.

The Brattle Group noted in 2019 that along with the traditional use of DR for peak demand reductions "load can now be managed to provide additional high value services, such as geographically-targeted demand reductions, load building and system balancing," and that such load flexibility could provide $15 billion in annual benefits by 2030.[12] But an overview of data on the RTO/ISO markets between 2009 and 2020 shows that DR participation has generally not moved beyond its use as a resource that is called upon during capacity shortages, rather than as an economic resource that responds to energy and ancillary services market prices throughout the year.

Mr. Centolella's testimony notes the limitations of DR that is used only during capacity shortfalls in MISO, finding that "MISO's dependence on LMRs [load-modifying resource] and EDRs [emergency demand response] that are only available in declared emergencies is not a reasonable long-term approach for to addressing current operational challenges or longer-term requirements."[13]

Below is a summary of the progress, or lack thereof, in RTO/ISO DR programs as reported by the market monitors in the 2009, 2010 and 2020 state of the market reports.[14] While the limited growth of DR participation is notable in MISO and SPP, where many state RERRAs have opted out, it is present in multiple RTOs/ISOs. While outside the scope of this NOI, it is therefore imperative that RTOs/ISOs and the Commission strive remove all barriers to innovation and growth in demand response participation in the markets.[15]

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[12] *The National Potential for Load Flexibility*, The Brattle Group (June 2019) at P2, available at: https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.

[13] Voltus Complaint, Docket No. EL21-12-000, Ex. A. Centollela Testimony at P24.

[14] CAISO and SPP's 2020 reports are not yet available, and therefore 2019 data is used.

[15] As Advanced Energy Economy (AEE) observed in its comments on the Voltus Complaint (Docket No. EL21-12-000) at P5, "structural barriers in the MISO participation model beyond the prevalence of these

Summary of RTO/ISO Demand Response Programs in 2009 and 2020

MISO: In 2020, the types of DR products were essentially the same as those offered in 2009. [16] These products are categorized as:

Emergency DR, which are DR resources that MISO calls upon in anticipation of a system emergency, and which include: Behind-the Meter Load Modifying Resources (LMR-BTMG); resources participating in legacy interruptible regulated utility programs (LMR-DR) or Emergency DR which is not obligated to respond. LMRs count as capacity resources that meet the reserve requirement, while Emergency DR does not.

Economic DR, which respond to energy or ancillary services prices, and are not only available during emergencies. Economic DR includes Type I, which is a fixed quantity of DR and Type II, dynamic resources that respond to energy and ancillary services prices.

Potomac Economics, the independent market monitor for MISO, stated in the 2009 State of the Market (SOM) report that "emergency DR is not price-responsive and does not participate directly in Midwest ISO markets."[17] Further, "[d]ynamic pricing is the most efficient form of

state opt-outs are limiting participation by technically capable demand response resources. Reversing the opt-outs alone is unlikely to be sufficient to remedy the unjust, unreasonable, and unduly discriminatory market rules that are diminishing opportunities for demand response to compete in MISO."

[16] Potomac Economics, *2020 State of the Market Report for the MISO Electricity Markets* at P107-108, available at: https://www.potomaceconomics.com/wp-content/uploads/2021/05/2020-MISO-SOM_Report_Body_Compiled_Final_rev-6-1-21.pdf; *2009 State of the Market Report for the Midwest ISO* (June 2011) at P128, *available at:* https://www.potomaceconomics.com/wp-content/uploads/2017/02/2009-State-of-the-Market-Report.pdf. The Midwest ISO is now the Midcontinent ISO.

[17] *2009 State of the Market Report for the Midwest ISO* at P128.

DR" but for this category just 4 units totaling 111 MW of capacity participated in 2009.[18] In 2010, Economic DR amounted to just one percent of all demand response resources in MISO.[19]

In the 2020 SOM report, the MISO market monitor again referred to dynamically priced DR as "the most efficient form of DR."[20] But the total Type I and II economic DR accounted for only 7 percent of total DR resources in 2020, of which just 101 MW of were price responsive DR (Type II) , *below* the amount of Type II participating in 2009.[21] DR in total, due to the increase in load modifying resources, has increased as a share of capacity from 6.8 to 8.4 percent between 2009 and 2021.[22] But the market monitor noted that the amount of such resources will likely drop over the next few years as a result of MISO's recent and proposed accreditation changes to LMRs.[23]

SPP: As with MISO, little progress has been made in DR participation in SPP markets. DR in SPP participates either as a dispatchable resource or a block resource—the first is "associated with controllable load and/or a behind-the-meter generator that is dispatchable on a

[18] *Id.* at P130.

[19]Potomac Economics, *2010 State of the Market Report for the MISO Electricity Markets* (June 2011), Table 3 at P136, available at https://www.potomaceconomics.com/wp-content/uploads/2017/02/2010-State-of-the-Market-Report.pdf. Data from 2009 on economic DR is not comparable to later years because pumped storage resources that had been the largest provider of DRR Type I stopped participating as DRR in September 2009 (see SOM Report at 133).

[20] Potomac Economics, *2020 State of the Market Report for the MISO Electricity Markets - Analytical Appendix* (May 7, 2021), at P172, available at https://www.potomaceconomics.com/wp-content/uploads/2021/05/2020-MISO-SOM_Appendix_Compiled_Final_rev-6-1-21.pdf

[21] *2020 State of the Market Report for the MISO Electricity Markets - Analytical Appendix*, Table 18 at P172.

[22]*2009 State of the Market Report for the Midwest ISO*, Table 5, at P134; 2021/2022 Planning Resource Auction (PRA) Results (April 15, 2021) at 10, available at https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

[23] *2020 State of the Market Report for the MISO Electricity Markets* at P107. The State of the Market report does not clarify if these are dispatchable on a 5-minute basis.

5-minute basis,"[24] and the second is "not dispatchable on a 5-minute basis but can be committed and dispatched in hourly blocks."[25] SPP does not have a capacity market, and dispatchable DR can be counted as a reduction in net peak demand when determining compliance with SPP's resource adequacy requirement, as long as the amount aligns with the state's DR accreditation program.[26]

There was no DR participation in SPP's markets until the implementation of the Integrated Marketplace in March 2014. At that time, six DR resources were registered with a total of 48 MW of capacity, but those resources then withdrew from the market in January 2015. Since that time, there were no registered DR resources in the SPP market until December 1, 2019 when three resources became active, accounting for just 0.3 MW of capacity.[27]

SPP recently developed new rules for accreditation of demand-side resources to meet regional resource adequacy requirements. In 2020, SPP reports approximately 692 MW of controllable and dispatchable demand response (CDDR) in the region that reduce the net peak demand.[28] However, these CDDR resources are not required to register for participation in SPP's Integrated Marketplace and are self-dispatched regardless of market price.

[24] SPP Integrated Marketplace Protocols, Sections 4.2.2.5.1 (2021)

[25] SPP Integrated Marketplace Protocols, Sections 4.2.2.5.1 and 4.2.2.5.2 (2021)

[26] SPP, *Resource Adequacy Instruction Manual* (2021) at P11-12, *available at:* https://spp.org/Documents/45078/Resource%20Adequacy%20Workbook%20Instruction%20Manual%20 20201230.docx.

[27] SPP Market Monitoring Unit, *2019 State of the Market Report* (May 2020), at P45, *available at:* https://www.spp.org/documents/62263/2019%20asom%20stakeholder%20presentation.pdf.

[28] SPP, *2020 SPP Resource Adequacy Report* (2020), Table 1 at P4, *available at:* https://www.spp.org/documents/62405/2020%20spp%20june%20resource%20adequacy%20report.pdf.

PJM: PJM's market monitor, Monitoring Analytics, reports that the capacity market has accounted for almost all DR revenue since its implementation in 2007.[29] In the Base Residual Auction for the 2020/21 delivery year, 10,703 MW of DR cleared, equal to 5.4 percent of capacity,[30] compared to 196 megawatts of economic DR reductions in the same delivery year the 2020 calendar year.[31] Emergency DR revenue, which includes capacity and emergency energy revenue, accounted for 99.1 percent of all revenue received by DR providers, the economic program for 0.1 percent, synchronized reserve for 0.4 percent and the regulation market for 0.4 percent.[32] The only state RERRAs that have opted out of PJM DR programs are Indiana, Michigan and North Carolina, which have small portions of their states within the RTO.[33]

ISO-NE: In 2009, ISO-NE operated three real-time, reliability-activated and two price-activated DR programs—one based on day-ahead location marginal prices (LMPs) and the other on forecasted real-time LMPs.[34] In that year, just 3 percent of the total DR participated in the price-activated programs.[35] These programs expired when ISO-NE established a price-responsive demand (PRD) program integrated into the energy markets, which was established in June 2018.

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[29] PJM, Monitoring Analytics LLC, *2020 State of the Market Report (*March 11, 2021) at P311, Figure 6-1 at 312, *available at:* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-sec6.pdf.

[30] *Id.* at Table 6-3 at P313.

[31] *Id.* at Table 6-4 at P329. There were 2,040 MW of Economic DR registered, but Monitoring Analytics at P 328 points out that these registered MW "are not a good measure of the MW available for dispatch" because these resources "are not required to offer any MW."

[32] *Id.* at P305.

[33] RERRAs that Prohibit, Permit or Condition Retail Participation in PJM Demand Response Programs, https://www.pjm.com/-/media/etools/dr-hub/opt-in-opt-out-rerra-evidence-for-dsr.ashx; *also see* Voltus Complaint (Docket No. EL21-12-000) at Exhibit C.

[34] ISO-New England Inc. Internal Market Monitor. *2009 Annual Markets Report* (May 18, 2010) at P48-49, available at: https://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/other/amr09_final_051810.pdf.

[35] *Id.* at Table 3-14 at P94.

In 2020, the ISO-NE market monitor reports that PRD resources represented low levels of dispatch – just 3.2 MW in the day-ahead energy market and 4.3 MW in the real-time energy market in the 2020 calendar year, and only one percent of the capacity obligations in the Forward Capacity Auction 11, procuring capacity for the 2020/21 delivery year.[36] DR as a capacity resource equaled 9 percent or 3,211 MW of capacity in that delivery year, but that resource also includes energy efficiency, which the ISO terms "passive DR."[37]

CAISO: In 2009, the vast majority of DR consisted of programs for managing peak summer demands developed by the state's three major investor-owned utilities, which were either reliability-based interruptible load programs or retail-based price responsive programs.[38]

In 2010, the ISO implemented a new product known as proxy demand resources, which allows DR to be bid and dispatched by the ISO.[39] The CAISO market monitor reported in the 2019 report that both utility and third-party DR programs have increasingly participated directly in ISO markets. Between 2018 and 2019, total registered proxy DR capacity increased from 700 MW to about 1,700 MW, which then dropped slightly to about 1,500 MW in 2018. [40] Moreover,

[36] ISO-New England Inc. Internal Market Monitor, *2020 Annual Markets Report*, (June 9, 2021) at P133-134, *available at*: https://www.iso-ne.com/static-assets/documents/2021/06/2020-annual-markets-report.pdf.

[37] *Id.* at P27.

[38] California Independent System Operator Department of Market Monitoring, *2009 Annual Report on Market Issues and Performance* (April 2010) at 2.7-2.8, *available at:* http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf.

[39] California Independent System Operator Department of Market Monitoring, 2010 *Annual Report on Market Issues and Performance* (April 2011) at P29, *available at:* http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[40] California Independent System Operator Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance* (June 2020) at P51, *available at:* http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf.

in total, as a capacity resource, DR grew from 0 GW to 3.8 GW between 2012 and 2019.[41] California has not exercised the RERRA Opt-Out.

NYISO: As with other RTOs/ISOs, almost all of the DR resources in the NYSIO are reliability resources, primarily Special Case Resources which sell into the capacity market. In 2009, these resources accounted for nearly 90 percent of the DR resources[42] and in 2020 accounted for 1,198 of the 1,199 MW of DR.[43] There are also programs that allow for DR participation in the Day-Ahead energy market and ancillary services markets. New York State has not exercised the RERRA opt-out.

Potomac Economics, the NYISO's independent market monitor, stated in the 2009 SOM report that "price-responsive demand has great potential to enhance wholesale market efficiency because modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation."[44] Although there has been little improvement of the participation of these resources, the market monitor reports in the 2020 SOM that the ISO "has been working on a series of market design projects that are intended to facilitate more active participation by consumers."[45] Such changes include rules that authorize third party metering; allow resources that provide wholesale market services to also

[41] *Id.* at 17.

[42] Potomac Economics, *2009 State of the Market Report for New York ISO*, at P127, *available at:* https://www.potomaceconomics.com/wp-content/uploads/2017/02/NYISO-2009-SOM-Report.pdf.

[43] Potomac Economics, *2020 State of the Market Report for the New York ISO Markets* at P119-120, *available at*: https://www.potomaceconomics.com/wp-content/uploads/2021/05/NYISO-2020-SOM-Report.pdf.

[44] *2009 State of the Market Report for New York ISO* at P132.

[45] *2020 State of the Market Report for the New York ISO Markets* at P119.

provide retail market services; and allow large consumers and aggregations of smaller consumers to participate more directly in the market.[46]

As shown, there has been limited progress in expanding wholesale DR participation in the areas where it can provide significant benefits, which includes both energy and ancillary services markets. While there has been consistent participation of DR as a resource that can be called upon during capacity shortfalls, such participation limits the benefits attainable from this resource.

In its analysis of the significant potential for an expansion of load flexibility, the Brattle Group found that "nearly 40% of the 2030 potential can be achieved simply by modernizing existing conventional programs through revamped program design and customer engagement."[47] In other words, allowing for more competition and innovation from non-utility third party ARCs can be one important avenue to unlock this potential.

Q3) To what extent have changes in the resource mix since 2009 increased the need for aggregations of demand response in RTO/ISO markets, particularly demand response that can respond to operator instructions in real time? Have impacts of these trends been different in states that have adopted the Demand Response Opt-Out?

The evolving U.S. resource mix since 2009 demonstrates a critical need for flexible loads to maintain system reliability, resilience and market operations.

The nation's bulk power system and wholesale electricity markets have undergone significant and unprecedented changes since 2009. The rapid scale-up of renewable generation combined with aggressive energy efficiency investments and transportation and building electrification nationwide is leading to a fundamental shift in the patterns of electricity

[46] *Id.*

[47] The Brattle Group (2019) at P2.

generation and consumption. Although the overall amount of annual net electricity generation in the U.S. remained at somewhat consistent levels from 2009-2020[48], the nation's generation resource mix exhibited a rapid shift in fuel sources unlike any decade before it.

The transformation of the U.S. generation mix has been characterized by the retirement of baseload, synchronous generating facilities and the integration of more distributed generation, demand response, gas combined cycle generating facilities, and the rapid expansion of non-synchronous variable energy resources (VERs) such as wind and solar. To a lesser but growing extent, emerging technologies such as energy storage resources (ESRs) are also contributing to the evolving resource mix.

Observed changes to the nation's resource mix are driven by many factors, including state and local energy policy goals, increasingly stringent environmental regulations, consumer adoption of energy efficiency, and competitiveness of cost-effective wind and solar generation resources. As shown in Figure 1, EIA data demonstrates significant changes to the composition of U.S. generation resources since 2009:

- Solar generation increased 15,250% from 2009 to 2020. EIA reported 132 terawatt-hours (TWh) of solar electricity generated in 2020 (including 91 TWh of utility-scale solar and 42 TWh of small scale solar) versus a mere 864 GWh of solar in 2009.[49] [50]

[48] According to EIA data, U.S. annual net generation was down ~2% in 2020 compared to 2009 in 2020, with annual deviation ranging ~5% across all years 2009-2020.

49 EIA data did not include small-scale solar in 2009.

[50] EIA, Form 860 Data (2020), Electric Power Monthly, February 2021, Table ES1.B.

- Wind generation has increased 510% since 2009.[51] Wind jumped from the 6th to 4th largest generation fuel source in the U.S. from 2009 to 2020. [52] EIA reports 117 GW of installed wind capacity operating in the U.S. at the end of 2020, which is 10% of all installed capacity.[53]
- Annual electricity generation from coal dropped 61% in 2020 compared to 2009. 90 GW of coal generation capacity retired between 2009 and 2020.[54]
- Gas is now the largest generation fuel source in the U.S. in 2020, up 83% from 2008.
- Nuclear generation has remained steady since 2009, dropping only 2% from 2008 levels in 2020. It is now the nation's second largest generation source.
- In 2020, EIA reported 2,087.6 MW of battery storage capacity operating across the country. The vast majority of these systems were installed between 2015-2020.[55]
- EIA reports 31 GW of potential peak DR resource savings across all active utility DR programs in 2019, with actual savings of 11.3 GW (36 percent of the potential). For RTOs/ISOs, EIA data shows 17.2 GW of potential peak demand savings across all

[51] EIA Form 860 Data shows that the U.S. generated over 337 TWh of wind in 2020, versus 55 TWh in 2009.

[52] EIA Form 860 data (2020).

[53] EIA, *Electric Power Monthly* (Feb 2021), showing data for Dec 2020.

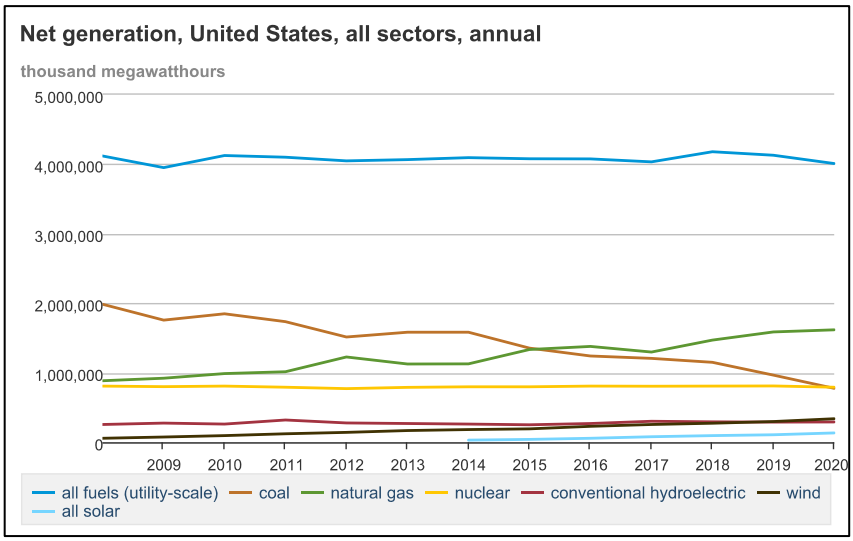
[54] EIA Form 860 data (2020) (file: Gen_Data_Y2020release).

[55] EIA reports that 193 of the 231 battery storage systems reported in Form 831 were installed between 2015-2020. Additionally, EIA reports more than 30% of existing large-scale battery storage power capacity in 2018 was located in the PJM Interconnection, most of which was built from 2014-2016. This was most likely the result of changes in PJM's market for frequency regulation (a grid service that helps balance momentary differences between electricity demand and supply within the transmission grid) in 2012 which created a specific requirement for fast response resources, such as batteries. Available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf *(last accessed July 18, 2021).*

active DR programs in 2019, with actual savings of 7.2 GW reported in 2019 across all programs in utilities operating in RTOs/ISOs (42 percent of the potential).[56]

- In 2013, the earliest year for which EIA provides data on utility DR programs, utilities report a total of 27 GW of potential peak demand savings across all active utility DR programs, with actual savings of 11.8 GW (44 percent, which is higher than in 2019).[57]

Figure 1. Annual Net Generation, United States, All Sectors



Source: U.S. Energy Information Administration (EIA)

The growth of renewable resources cuts across all RTOs/ISOs. Lawrence Berkeley National Laboratory's analysis of the interconnection queue found that as of the end of 2020, there were 680 GW of zero-carbon generation proposed, out of a total 755 GW of total capacity, with those resources "widely distributed across the U.S."[58]

[56] EIA Form 861 Data (2019).

[57] EIA Form 861 data (2019).

[58] Lawrence Berkeley National Laboratory, *Queued Up* (May 2021) at P3, *available at: https://emp.lbl.gov/publications/queued-characteristics-power-plants*

Looking ahead, between now and 2030, EIA reports an additional 89.5 GW of synchronous generating facilities (e.g., coal, nuclear, and natural gas) are likely to retire across the country, the vast majority coming from coal unit retirements.[59] However, significant continued growth in both wind and solar capacity are projected nationwide through 2029 (see Figures 2 and 3). In particular, MISO, SPP, and PJM are projected to see significant increases in solar generation capacity. MISO and SPP are both expected to continue the last decade's trend to nearly double installed wind capacity in each region by 2029.

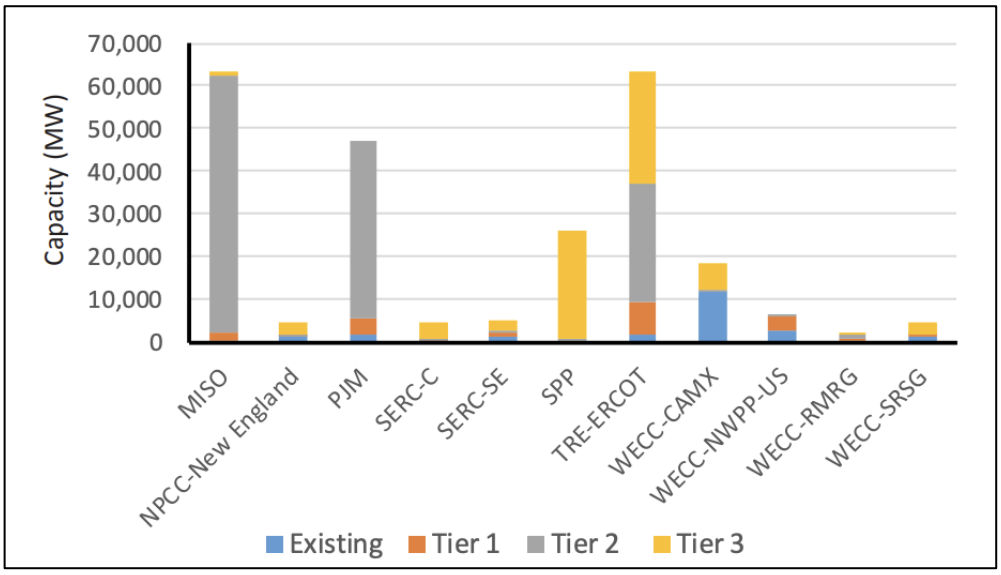
Other analyses show a much greater potential for renewable expansion to achieve carbon reduction policies to address climate change. For example, an analysis by the University of California-Berkeley of achieving a 90 percent carbon reduction by 2035 shows the construction of 1,200 GW of storage, wind and solar by 2035, along with the retirement of all existing coal plants.[60] The Rocky Mountain Institute found that electricity sector changes needed to achieve a 50 percent reduction in carbon emissions by 2030 would entail installing six to nine times today's approximately 200 GW of wind and solar capacity, approximately five times greater than the installation rate in 2020, and coal generation nearly eliminated by 2025.[61]

[59] EIA reports that ~57 GW of coal capacity will be retired through 2030.

[60] Goldman School of Public Policy, University of California-Berkeley, *2035: The Report* (2020), at Figure ES-4, available at: *http://www.2035report.com/wp-content/uploads/2020/06/2035-Report.pdf?hsCtaTracking=8a85e9ea-4ed3-4ec0-b4c6-906934306ddb%7Cc68c2ac2-1db0-4d1c-82a1-65ef4daaf6c1*.

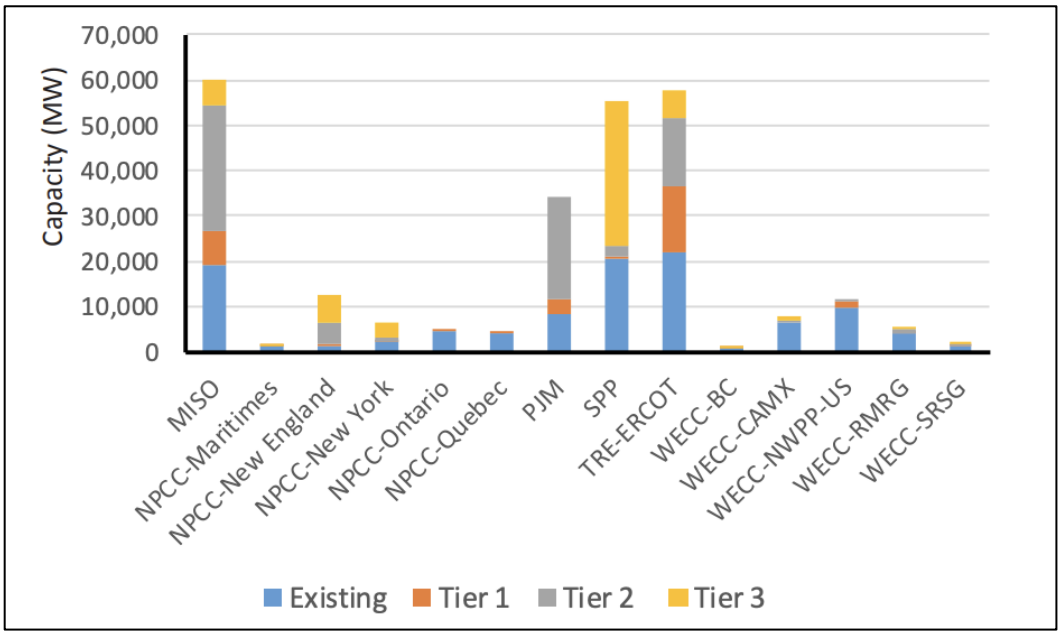
[61] Rocky Mountain Institute, *Policy Brief: US Sector-Level Strategies and Targets to Limit Warming to 1.5°C*, (April 2021), available at: https://rmi.org/insight/scaling-us-climate-ambitions/.

Figure 2. Solar Existing and Planned Nameplate Capacity (MW) by Region, 2020-29.



Source: NERC

Figure 3. Wind Existing and Planned Nameplate Capacity (MW) by Region, 2020-2029.



Source: NERC

The shift towards renewables is dramatic within RTOs and ISOs where states have exercised the DR Opt-Out Rule. MISO's generation mix has shifted from 83 percent natural gas and coal in 2005 to 67 percent in 2020, along with a shift from almost no renewables to 13 percent solar and wind. The renewable share is expected to grow to between 20 and 35 percent by 2030, depending upon the assumptions made.[62] SPP reports significant growth in wind energy resources as well as natural gas from 2011-2020, with a comparatively small but significant growth in participation by utility-scale solar resources. Wind generation has been and continues to be the fastest growing generation resource in SPP, increasing by 256% in SPP from 2009-

[62] MISO Response to the Reliability Imperative (April 2021) at 7, available at: https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL_updated%204-29-2021504018.pdf.

2020.[63] In 2021 wind surpassed coal to become the largest generation resource in the SPP region.[64]

These dramatic shifts demonstrate the importance of an expansion of the amount and types of DR. Multiple studies have found that the growth of VERs, electrification of transportation and buildings, and more extreme weather events all create a need for greater DR and in particular DR that can respond at all times, and not just during peak periods. Moreover, as a flexible resource, DR has the benefit of providing needed flexibility without the emissions and costs of conventional resources.

An NREL analysis from 2018 examined the role of DR found that "demand response innovations of the last several decades, and the potential for emerging technologies such as electric vehicles to be operated flexibly, represent an opportunity to quickly transition to providing reliable electricity service with significantly less pollution intensity by ensuring demand response is implemented to serve as a flexible complement to wind and solar PV generation."[65] NREL also points out that "as a potential source for supplying increased flexibility, DR is particularly attractive because of the smaller capital investment required,"[66] and that "additional services, specifically economic energy shifting, regulation reserve signal

[63] Based on SPP Marketplace Portal data: https://marketplace.spp.org/pages/generation-mix-historical.

[64] Based on SPP Marketplace Portal data: https://marketplace.spp.org/pages/generation-mix-historical. Solar represents a small but significant area of growth in SPP. In 2011, SPP did not report any utility-scale solar operating in the region. By 2020, SPP reported 12.6 GWh of annual net solar generation.

[65] National Renewable Energy Laboratory, *Potential Roles for Demand Response in High-Growth Electric Systems with Increasing Shares of Renewable Generation* (December 2018) at P21, *available at:* https://www.nrel.gov/docs/fy19osti/70630.pdf.

[66] *Id.*

following, and other active forms of load balancing … typically provide additional economic value or cost savings to the system."[67]

The Brattle Group found in 2019 that load flexibility (and not just peak reductions) is needed to address three industry mega-trends: renewable growth, grid modernization and electrification – trends which are impacting all of the RTOs/ISOs to varying degrees. Brattle found there to be 200 GW of cost-effective load flexibility potential in the U.S. by 2030 and identifies the following beneficial roles for DR: shifting consumption to times of low net load; providing ancillary services; geographically targeted deferral capacity upgrades; and reducing the system costs of electrification while adding value to smart appliances and electric vehicles.

Gridworks and GridLab also found there to be multiple valuable roles that DR can provide within the modern grid, including reshaping customer loads over time; shifting periods of high energy demand to periods of low demand (such as through electric vehicle charging or heavy appliance operation during times when power supplies are abundant); shedding load during peak load events; and providing ancillary grid services, such as rapidly smoothing load or regulating voltage in response to sudden grid disturbances.[68]

The increasing importance of flexible DR was recognized by PJM Interconnection, ISO-New England and the New York ISO in their issuance in March of "Foundational Market Objectives for a Reliable Future Grid," which included the following objective, among others:

> Continued Efficient Integration of Demand-Side Resources into Competitive Wholesale Markets. The transition to the future grid requires a wholesale market structure that allows for new and existing technologies to compete on equal footing. This includes the capability for wholesale price-responsive demand to play an active role in the wholesale

[67] *Id.* at P27.

[68] Gridworks and GridLab, *The Role of Distributed Energy Resources In Today's Grid Transition* (August 2018) at P5, *available at:* http://gridlab.org/wp-content/uploads/2019/04/GridLab_RoleOfDER_online-1.pdf.

markets, and the integration of a wide array of emerging load-shifting and distributed-resource technologies.[69]

The role of flexible demand specifically in the integration of renewable resources is also widely recognized. For example, NYU's Institute for Policy Integrity notes that "flexible and responsive electricity demand is especially important for integrating renewables,"[70] and C-Power recently stated that "increased participation in demand response programs at the ISO and utility levels across the US is providing new tools for grid operators to harmonize their grids' reliability with their drive toward a future of cleaner generation fuel mixes."[71]

Finally, the recent extreme cold that occurred this winter in Texas, MISO, and SPP shows the need for flexible DR as a tool to avoid or mitigate rolling blackouts, which often adversely impact more vulnerable communities. Alison Silverstein noted at the recent Commission technical conference on Climate Change, Extreme Weather and Electric System Reliability that "for the bulk power system, measures such as demand response, better building envelopes, and more efficient and controllable heaters and air conditioners will moderate and stabilize electric demands to lower peaks and net peaks and provide needed grid flexibility tools. These will make the bulk power system safer, reliable, and more economical at the same time that they help customers and communities."[72]

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[69] PJM Interconnection, ISO-New England and the New York ISO, *Foundational Market Objectives for a Reliable Future Grid,* at P2, *available at*: https://www.pjm.com/-/media/library/reports-notices/testimony/2021/20210323-ferc-capacity-tech-conference-testimony.ashx.

[70] Institute for Policy Integrity, *Resource Adequacy in a Decarbonized Future* (March 2021) at P36, *available at:* https://policyintegrity.org/publications/detail/resource-adequacy-in-a-decarbonized-future.

[71] C-Power, *State of Demand-Side Energy Management, Volume III* (2021) at P28, *available at:* https://cpowerenergymanagement.com/demand-side-2021-webinar-series/.

[72] *Prepared Remarks of Alison Silverstein*, Alison Silverstein Consulting, Climate Change, Extreme Weather and Electric System Reliability Technical Conference, Docket No AD21-13-000 (June 1, 2021) at P 2, available at: https://ferc.gov/media/alison-silverstein-consulting.

Given that the growth of renewables, more extreme weather events, and expanding electrification are occurring across the RTOs/ISOs, the need for a removal of all barriers to an expansion and innovation in DR and flexible demand has never been greater.

> ***Q4) The North American Electric Reliability Corporation (NERC) has stated that demand response provides transmission system operators with additional system-balancing tools to maintain bulk-power system reliability NERC has also stated that, as the resource mix changes, flexible resources that can be called upon on short notice, including demand response, are needed to ensure resource adequacy and meet ramping needs. To what extent can demand response aggregations provide real- time balancing and essential grid services, such as frequency response and ramping capability, to support bulk-power system operations? Are third- party demand response aggregators equally able to provide real-time balancing and essential grid services, or are utility-operated programs better suited to provide them? Are transmission system operators better able to leverage these capabilities given developments in technology and infrastructure since 2009? (Footnotes removed.)***

As shown in response to Question 3, multiple recent studies demonstrate the valuable role that DR can play in not just resource adequacy, but in providing needed flexibility, ramping capability and ancillary services to meet the needs of the nation's current and projected resource mix. NERC found in the most recent long-term reliability assessment that this "new resource mix includes natural-gas-fired generation; unprecedented proportions of nonsynchronous resources, including renewables and battery storage; DR; smart- and micro-grids; and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty."[73]

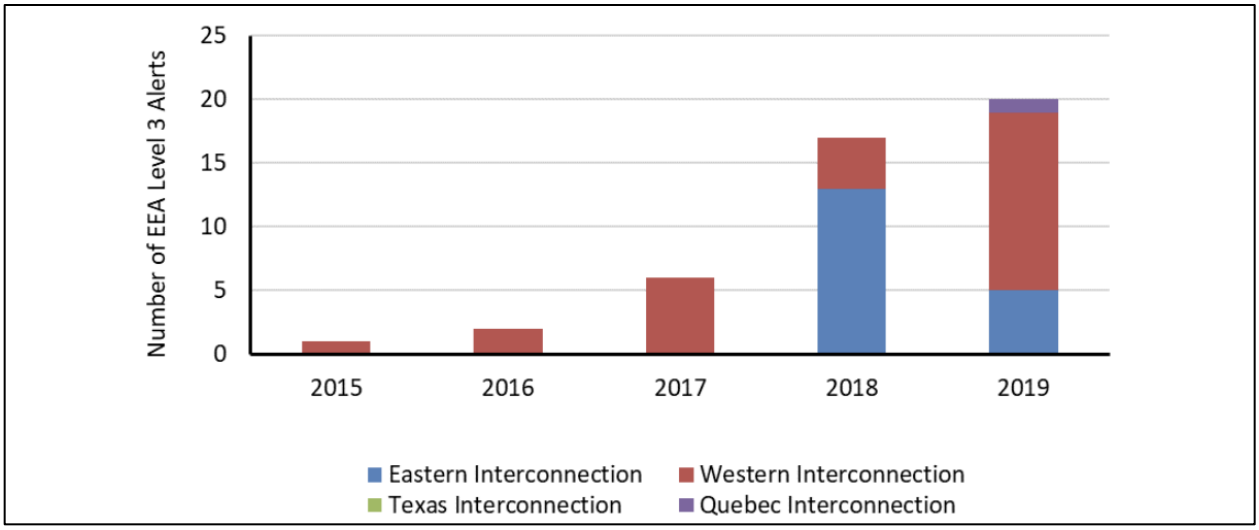
The Brattle Group's study and other analyses cited in response to Question 3 demonstrate that greater participation of DR, including within distributed energy resource aggregations, will

[73] NERC, *Long-Term Reliability Assessment* (2020) at P18, *available at:* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

be essential to providing a lower cost and emissions free means to provide multiple services that can reduce such uncertainties.

NERC has reported a dramatic increase in the number of Level 3 Energy Emergency Alerts (EEA) declared across both the Eastern and Western Interconnection in recent years. EEA Level 3 events are firm-load interruptions that are imminent or in progress due to capacity or energy deficiencies. 74 In 2019 alone, 20 EEA Level 3 alerts were declared, three more than the previous year. The most common reason for an EEA Level 3 alert declaration was to recover reserves. Figure 3 below shows the year-over-year changes in EEA Level 3 by Interconnection.[74]

Figure 5. Number of EEA 3 Level Alerts by Interconnection, 2015-2020.



Source: NERC

DR Can Ease Capacity Constraints in Regions with Tight Reserve Margins.

According to NERC, MISO (a region where many states have opted out) will have tighter reserve margins in 2021 and future years, and "action is needed to ensure future resource

[74] NERC, *Long-Term Reliability Assessment* (2020), *available at:* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf (The 20 EEA Level 3 alerts declared in 2019 lasted a total of 27.65 hours. The largest load loss associated with an EEA Level 3 in 2019 was 150 MW.)

adequacy, especially beginning in 2025 when their ARM [anticipated reserve margin] is projected to fall below their RRM [reference reserve margin].[75]

DR, by its very nature, and unlike new generators or transmission, does not take years to build and work through interconnection queues. As an expedient option to address supply and demand imbalances, DR participation should immediately be enabled and encouraged across all regions facing immediate challenges to meet reserve margin requirements. Removing the DR Opt-Out Rule would support this.

As shown in the response to Q1, DR has largely stagnated in many RTOs/ISOs and is primarily utilized to reduce peak load during emergency events. Allowing DR to participate more actively in the provision of Essential Reliability Services will improve grid reliability. Whether that can be better accomplished by third-party ARCs or utilities does not need to be answered definitively; instead, removing barriers to competition from third-party aggregates will create more opportunities for DR to provide multiple services.

B. Questions Regarding Potential Benefits of Removing the Demand Response Opt-Out

Q5) What are the potential benefits of removing the Demand Response Opt-Out, including any benefits not considered by the Commission in Order Nos. 719 and 719-A, and considering any changed circumstances that may be relevant? Please note if such benefits were not previously highlighted in Order Nos. 719 and 719-A. Please provide quantitative estimates, if possible. In addition, please describe the types of entities to which any benefits would accrue.

Removing the DR Opt-Out Rule will support the Commission fulfilling its statutory responsibility to ensure that jurisdictional rates are just and reasonable.

Effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new

[75] NERC, *Long-Term Reliability Assessment* (2020) at P12, *available at:* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

technologies. Improving the competitiveness of organized wholesale energy markets is integral to the Commission fulfilling its statutory mandate under the Federal Power Act (FPA) to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[76]

Few dispute that enabling market access for all of the services DR is capable of providing helps to ensure just and reasonable rates.[77] In Order No. 719 the Commission found that DR can provide "competitive pressure to reduce wholesale power prices, providing for the more efficient operation of organized markets, helping to mitigate market power and enhance system reliability, and encouraging development and implementation of new technologies, including renewable energy and energy efficiency resources, distributed generation and advanced metering."[78] DR "balance[es] supply and demand, and thereby, helps produce just and reasonable energy prices . . . because customers who choose to respond will signal to the RTO or ISO and energy market their willingness to reduce demand on the grid which may result in reduced dispatch of higher-priced resources to satisfy load."[79] Furthermore, the Commission has identified that DR also "tends to flatten an area's load profile, which in turn may reduce the need to construct and use

[76] 18 CFR Part 35 at P6.

[77] *See generally* Huber, *Demand Response and Market Power*, 100 Iowa Law Rev. Bull. 87 (2015), *available at: https://ilr.law.uiowa.edu/online/volume-100/demand-response-and-market-power/* (last accessed July 23, 2021); Spees et al., *Demand Response and Electricity Market Efficiency*, *Carnegie Mellon Electricity Industry Center Working Paper* (Jan 2007), *available at: https://www.cmu.edu/ceic/assets/docs/publications/working-papers/ceic-07-01.pdf* (last accessed July 21, 2021); ACEEE, *Maryland Benefits: Examining the Results of EmPOWER Maryland through 2015* (January 2017), *available at:* https://assets.ctfassets.net/ntcn17ss1ow9/2fxOYY4ZiZA6Onx2pc3Iv4/336b77a007b27629fdfdfae48b93a254/ACEEE_Report__1.pdf (last accessed July 21, 2021).

[78] 125 FERC ¶ 61,071 at P28.

[79] Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 at P6 (March 15, 2011) ("Order 745").

more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy."[80] A plethora of studies confirm the beneficial cost reductions due to demand response.[81]

For years the Commission has found that DR increases competition and leads to just and reasonable rates.[82] Yet, by allowing RERRAs to keep ARCs out of wholesale markets, the Commission has ensured that the competitive pressure DR can provide is unavailable in many areas of the country. This is particularly true in RTOs/ISOs such as MISO and SPP where most utilities remain vertically integrated and where RERRAs have placed bans and restrictions on DR resource participation by ARCs in wholesale markets. Nearly every state in the MISO footprint has issued a ban on third-party DR aggregators. The resulting lack of competition from third-party ARCs has led to DR far below its potential across wholesale markets. (See comments above in Q1.)

[80] 18 CFR Part 35 at Footnote 16.

[81] A study by PJM demonstrated that "a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent." 18 CFR Part 35 at P8 (citing ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets (Oct. 16, 2007); Ahmad Faruqui et al., *The Power of Five Percent*, The Electricity Journal (Oct. 2007) (conservatively estimating that a five percent reduction in peak demand through DR programs could lead to $35 billion in savings over a 20 year period), *available at:* https://www.sciencedirect.com/science/article/abs/pii/S1040619007000991?via%3Dih ub (last accessed July 21, 2021); FERC Staff, *A National Assessment of Demand Response* (potential to reduce peak demand by ten to twenty percent through demand response, effectively eliminating the equivalent of between 1,000 and 2,500 peaking units); Stoll, Brady, Elizabeth Buechler, and Elaine Hale, *The Value of Demand Response in Florida*, 30 THE ELECTRICITY JOURNAL 57 (Nov. 10, 2017) (studying value of demand response under high renewable penetration scenarios and finding $76 million to $259 million in cost savings due to increased deployment of demand response); Potomac Economics, *2019 State of the Market Report* (June 2020), Analytical Appendix at P168 (citing "[r]eductions in price volatility and other market costs") *available at:* https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-MISO-SOM_Report_Final_6-16-20r1.pdf (last accessed July 21, 2021); Lawrence Berkeley National Laboratory, *20205 California Demand Response Study* (March 2017), *available at:* https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf (last accessed July 18, 2021).

[82] *See* Order No. 719; Order No. 745; Order No. 2222.

In Order Nos. 719 and 719-A, the Commission focused on discriminatory DR pricing rules in operating reserve markets in emergency situations. In particular, the Commission observed in Order No. 719 that due to the lack of DR participation, existing RTO and ISO market rules appeared to be unjust, unreasonable, and unduly discriminatory or preferential during periods of operating reserve shortages.[83] Noting that "these rules may not produce prices that accurately reflect the true value of energy in such an emergency and, by failing to do so, may harm reliability, inhibit demand response, deter new entry of demand response and generation resources, and thwart innovation"[84] the Commission proposed to reform market rules governing price formation in RTO and ISO energy markets during operating reserve shortages.

The requirements of Order Nos. 719 and 719-A apply to competitively bid markets for energy imbalance, spinning reserves, supplemental reserves, reactive supply and voltage control, and regulation and frequency response, or to the markets of their functional equivalents.[85] The Commission emphasized that competitiveness within ancillary services markets, as well as the system reliability, would be enhanced through increased participation of DR resources.[86]

One of the Commission's stated goals underlying Order Nos. 719 and 719-A is to allow DR resources to participate in organized markets on a basis comparable to other resources and to

[83] 137 FERC ¶ 61,215 at P8. "We continue to find that Commission regulation of demand response participation in the organized wholesale energy markets and the market rules governing that participation is essential to the Commission fulfilling its statutory responsibility to ensure that jurisdictional rates are just and reasonable."

[84] 125 FERC ¶ 61,071 at P90.

[85] *Id.* at P28. "The Commission requires that demand response resources that are technically capable of providing the ancillary service within the response time requirements, and that meet reasonable requirements adopted by the RTO or ISO as to size, telemetry, metering and bidding, be eligible to bid to supply energy imbalance, spinning reserves, supplemental reserves, reactive and voltage control, and regulation and frequency response."

[86] 125 FERC ¶ 61,071 at P31.

encourage development of complementary new technologies, including renewable energy, energy efficiency, distributed generation and advanced metering.[87] The Commission acknowledged the potential for development of DR resources to provide benefits to consumers by "encouraging development and implementation of new technologies, including renewable energy and energy efficiency resources, distributed generation and advanced metering."[88] However, the Commission declined to address participation of energy efficiency, energy storage and other demand-side resources, which were later addressed in Order Nos. 841 and 2222.[89] The Commission has consistently declined to adopt a mechanism similar to the DR Opt-Out Rule in those proceedings.[90]

In its two major rulemakings involving energy storage (Order No. 841) and distributed energy resources (Order No. 2222) after the Supreme Court's decision in *EPSA,*[91] the Commission declined to provide RERRA opt-outs, despite requests to do so. In the case of energy storage, the D.C. Circuit recently upheld FERC's authority to allow energy storage connected to the grid at the distribution level to participate in the wholesale markets without providing a RERRA opt-out.[92] Inconsistent approaches to RERRA opt-outs across Commission rules for different kinds of distributed resources have resulted in discriminatory treatment of DR

[87] *Id.* at P11.

[88] 125 FERC ¶ 61,071 at P 28.

[89] *Electric Storage Participation in Markets Operated by RTOs and ISOs*, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("Order 841"); *Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs*, 172 FERC ¶ 61,247 (Sept. 17, 2020) ("Order 2222").

[90] E.g., *AEE Declaratory Order,* 161 FERC ¶ 61,245 at P 57 (finding that RERRAs may not bar the participation of energy efficiency resources in wholesale markets unless the Commission gives RERRAs such authority, and declining to opine on the requirements the Commission would impose in the event that a RERRA requests such authority).

[91] *FERC v. EPSA*, 136 S.Ct. 760, 771 (2016) ("EPSA").

[92] *Nat'l Ass'n of Regulatory Util. Commissioners ("NARUC") v. FERC*, 964 F.3d 1177 (D.C. Cir. 2020).

resources across markets, possibly leading to unjust and unreasonable rates, which could be resolved by removal of the DR Opt-Out Rule.

Eliminating the DR Opt-Out Rule will enhance wholesale market competition by enabling more participation options for retail customers.

In its design of the DR Opt-Out Rule, the Commission stated that its intent was not to interfere with the operation of successful retail DR programs, place an undue burden on state and local retail regulatory entities, or raise new jurisdictional concerns.[93] While PIOs do not dispute a state's right and responsibility to ensure fair retail rates and distribution system reliability, PIOs disagree with the argument that limiting wholesale market participation is necessary for states to meet those objectives. States can and should address their responsibilities without needing to dictate the terms of wholesale market participation. Eliminating the DR Opt-Out Rule would have the benefit of improving market participation options for customers, which will ultimately enhance both bulk power system and distribution system reliability, as well as lowering both wholesale and retail rates.

Removing the DR Opt-Out Rule may enhance wholesale market competition between utility-operated DR assets and non-utility ARCs. This competition could lead to DR programs providing better services for customers in organized markets. While many incumbent utilities in the MISO and SPP footprints have some form of retail DR programs, as stated above in our response to Q1 and demonstrated in Voltus's complaint, those programs have not led to significant wholesale market participation from DR resources.[94] Several recent filings in MISO and SPP states give an indication of the state of retail DR programs in states that have opted-out,

[93] *Id.* P 155.

[94] Compl. of Voltus, Inc. Requesting Fast Track Processing, at 1–2, Docket No. EL21-12-000 (Oct. 20, 2020), Accession No. 20201020-5136 ("Voltus Complaint.")

and provide evidence that there are untapped opportunities in those states for greater DR penetration.[95] Eliminating the DR Opt-Out Rule may lead to better outcomes for those retail customers by allowing them to participate in better programs than are currently offered.

System Operators may benefit from the participation of aggregated DR resources that are currently excluded from wholesale market participation under the DR Opt-Out Rule.

DR has the potential to provide important resources for maintaining the stability of the bulk power system, to defer more costly upgrades to generation, transmission and distribution systems, and to deliver customer economic benefits.[96] As discussed in our response to Q1, DR resources have evolved significantly since 2009, as have the markets in which they operate. We

[95] For example, in Wisconsin (a state that has opted out), the Wisconsin Public Service Commission (WPSC) recently issued its Final Strategic Energy Assessment 2020-2026, finding that while demand response capacity reached up to 10% of statewide peak demand, it is rarely deployed. *See* Public Service Commission of Wisconsin, *Final Strategic Energy Assessment*, 5-ES-110 (Oct. 2020); *Also see* Michigan Public Service Commission, *Orders U-20628* and *U-20348* (Oct. 29, 2020) (The MPSC found benefits of demand response aggregation and agreed with a staff recommendation that incumbent utilities work with third-party aggregators to better manage DR portfolios. MPSC ordered reopening of Case No. U-20348 to review the MPSC's ban on DR aggregators. This renewed interest comes from Order 2222's removal of barriers for DERs, including DR, and from MSPC Case No. U-20628 exploring demand response in Michigan. While that process is ongoing in Michigan, the MPSC's interest in reassessing the existing aggregator ban is a recognition by the Commission that the status quo of total aggregation bans may be detrimental to demand response.); *Also see* General Staff of the Arkansas Public Service Commission (APSC) *Initial Comments and Legal Brief pursuant to Order No. 9*, August 28, 2020, Arkansas Public Service Commission Docket No. 09-090-U, *available at*: http://www.apscservices.info/pdf/09/09-090-U_53_1.pdf. (Staff of the Arkansas PSC, a state that has Opted-Out, recently argued regarding the state's ban on ARCs, "ARC participation in demand response programs provides a variety of public policy benefits. For example, wholesale demand response programs help to reduce costs which impact retail rates, protect the reliability of the grid, and reduce energy consumption, which in turn provides environmental benefits."); *And see* MidAmerican Energy Company, *Energy Efficiency Plan*, Iowa Utilities Board EEP-2012-0002 and EEP-2018-0002, 52 (May 4, 2020) at P55-56; Interstate Power and Light Co., *Revised Annual Report for 2019 Energy Efficiency Plan*, Iowa Utilities Board EEP-2018-0003, 30-31 (May 12, 2020).

[96] *See generally* Lawrence Berkeley National Laboratory, *20205 California Demand Response Study* (March 2017) at P1-1, *available at:* https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf (last accessed July 18, 2021).

are currently in what some refer to as the "third generation" of demand-side participation in the grid.[97]

As the resources and technologies underpinning the electrical grid have changed, so have market rules governing electricity production and compensation. Several of these changes to market rules better encourage, and more accurately compensate, flexible resources through market commitment and dispatch instead of out-of-market interventions by the grid operator."[98] The significant expansion and refinement of wholesale markets nationwide since Order No. 719 reflects both an acknowledgment of the benefits of wholesale market competition, as well as the growing demand for new, more flexible energy services and products by system operators.[99]

Although the requirements of Order Nos. 719 and 719-A did not obligate RTOs or ISOs to create new competitively-bid ancillary services markets, the RTOs and ISOs have since created new ancillary service markets and additional energy and capacity market products, many in which DR may participate.[100] When the Commission issued Order No. 745 in 2011,[101] it established several guidelines for DR participation in energy markets, finding that: (1) DR can provide benefits similar to generation resources; (2) Payments to DR resources should be at the full market price of energy; (3) A net-benefits threshold needs to be established; and (4) DR

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[97] C-Power, *State of Demand-Side Energy Management, Volume III* (2021) at P6, available at: https://cpowerenergymanagement.com/demand-side-2021-webinar-series/ (last accessed July 21, 2021).

[98] FERC, *2020 State of the Market Report* (March 2021) at P7, *available at:* https://www.ferc.gov/sites/default/files/2021-03/State%20of%20the%20Markets%202020%20Report.pdf (last accessed July 21, 2021).

[99] *Id.* at P6.

[100] National Renewable Energy Laboratory, Ela et al., *Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Penetration* (Sep 2014), *available at:* https://www.nrel.gov/docs/fy14osti/61765.pdf (last accessed July 21, 2021).

[101] *Demand Response Compensation in Organized Wholesale Energy Mkts.*, 134 FERC ¶ 61,187 (2011) ("Order 745"), *available at:* https://www.ferc.gov/sites/default/files/2020-06/Order-745.pdf (last accessed July 21, 2021).

should be able to set the energy market clearing price, if it can provide the next available megawatt in economic order.[102] After Order No. 745, the RTOs and ISOs continued to refine and expand market products, including new ramping products,[103] fast-start pricing,[104] operating reserves,[105] as a few examples.

Alongside the significant expansion in wholesale markets and the services they provide, there have similarly been significant improvements in the technology that ARCs offer to retail customers, including instant communication of dispatches, real-time visibility and control of load curtailment, immediate settlement of dispatch performance, and automated financial transactions between markets and customers, in part due to the proliferation of broadband, high-speed wireless communication.[106] More broadly, and as described in our answer to Q1, the adoption of emerging consumer technologies, such as smart thermostats, electric water heaters and smart meters, now allows for load to be managed through geographically targeted demand reductions, load building, and system balancing.[107] For example, through the use of state-of-the-art sensors

[102] 134 FERC ¶ 61,187 (2011) at P3-4.

[103] Midcontinent Indep. Transmission Sys. Operator, Inc., 149 FERC ¶ 61,095 (2014); Cal. Indep. Sys. Operator Corp., 156 FERC ¶ 61,226, at P 1 (2016); Southwest Power Pool, Inc., 172 FERC ¶ 61,027 (2020).

[104] Southwest Power Pool, Inc., 172 FERC ¶ 61,038 (2020); PJM Interconnection, L.L.C., 173 FERC ¶ 61,028 (2020); and New York Independent System Operator, Letter Order Accepting Compliance Filing, Docket ER20-659 (February 6, 2020).

[105] Midcontinent Indep. Transmission Sys. Operator, Inc., 170 FERC ¶ 61,075 (2020). PJM Interconnection, L.L.C., 171 FERC ¶ 61,153 (2020).

[106] The Brattle Group (June 2019).

[107] U.S. Department of Energy, *Grid-interactive Efficient Buildings* (April 2019), *available at:* https://www.energy.gov/sites/prod/files/2019/04/f61/bto-geb_overview-4.15.19.pdf. (Last accessed July 21, 2021) ("Grid-interactive efficient buildings are energy efficient buildings with smart technologies characterized by the active use of distributed energy resources to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way.")

and controls, grid-interactive efficient buildings can reduce 10-20% of commercial building peak load.[108]

DR resources and programs across the country today encompass a much broader variety of customer types, facilities, and technologies, operating across a range of timescales from transient responses in seconds to long-term shifts in daily behavior. The value created by DR depends on the timescale of the response. According to a 2017 study by Lawrence Berkeley National Laboratory, DR services may be grouped into four core service group categories: Shape, Shift, Shed and Shimmy:[109]

- Shape refers to reshaping customer load profiles through price response or on behavioral campaigns—"load-modifying demand response"—with advance notice of months to days.
- Shift represents demand response that encourages the movement of energy consumption from times of high demand to times of day when there is a surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation.
- Shed describes loads that can be curtailed to provide peak capacity and support the system in emergency or contingency events—at the statewide or regional level, in local areas of high load, and on transmission and distribution systems, with a range in dispatch advance notice times.

[108] *Id.* at 10-11.

[109] Lawrence Berkeley National Laboratory. *20205 California Demand Response Study* (March 2017) at P1-1, *available at:* https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf (Last accessed July 18, 2021).

- Shimmy involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.

In their 2008 comments on Order No. 719, PIOs urged the Commission to include other kinds of demand-side resources alongside DR resources, including energy efficiency resources, behind-the-meter distributed generation, and all other demand-side resources capable of providing a necessary grid service.[110] The example of a "virtual power plant" provided in PIO comments in 2008 is even more relevant today, as reflected in our response to Q3 above, which details the transformation of the U.S. generation mix, characterized by the retirement of baseload, synchronous generating facilities and the integration of more distributed generation, including DR, alongside the rapid expansion of wind and solar.[111]

As electricity systems integrate increasing levels of variable renewable energy, system operators are seeking technologies and strategies that increase their system's flexibility. Demand-side flexibility is important for renewable integration, alongside current and projected trends in growth of ESRs. In some cases, and in some regions, energy storage could partially mitigate the need for DR, because it could shift generation instead of having to shift load with DR.[112] However, through 2030, energy storage alone likely will not be able to provide the grid

[110] 125 FERC ¶ 61,071 at P18.

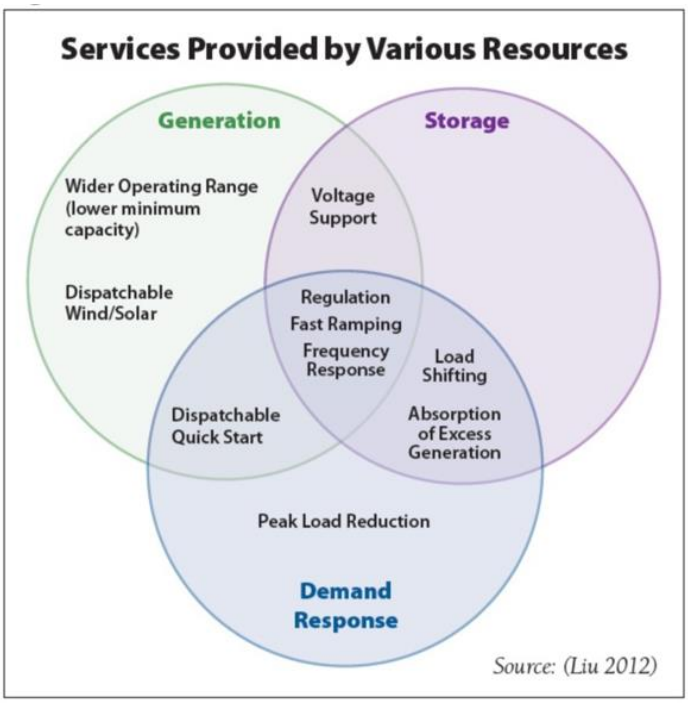
[111] El Khatib et al. Sandia National Laboratory, *Virtual Power Plant Feedback Control Design for Fast and Reliable Energy Market and Contingency Reserve Dispatch* (Aug 2008), *available at:* https://www.osti.gov/servlets/purl/1467792 (last accessed July 21, 2021).

[112] U.S. Department of Energy, *Demand Response and Storage Integration Study* (March 2016), *available at:* https://www.energy.gov/sites/prod/files/2016/03/f30/DOE-EE-1282.pdf (last accessed July 21, 2021)

reliability services necessary to integrate high levels of installed wind and solar capacity in some regions.[113]

The risk that the Commission has created with the DR Opt-Out Rule has the effect of forcing grid operators to put "all your eggs in one basket" by counting on having enough energy stored from peak generation times to serve peak load times, unless there is enough energy storage available such that a system has zero load curtailment. However, ESR penetration is nowhere near that level in any RTO/ISO, and is particularly low in SPP and MISO, so additional DR is needed to help align load and generation as much as possible. Figure 6 below illustrates how DR can interact with ESRs and generation resources together to provide essential services to the grid operators.

Figure 6. Services Provided by Various Resources



[113] U.S. EIA, *Battery Storage in the United States: An Update on Market Trends* (July 2020) *available at:* https://www.energy.gov/sites/prod/files/2020/12/f81/Energy%20Storage%20Market%20Report%202020_0.pdf (last accessed July 21, 2021).

Q6) What are the potential benefits of creating more consistency between the participation models for ARCs and distributed energy resource aggregators by removing the Demand Response Opt-Out? In light of market participation opportunities for energy efficiency resources, electric storage resources, and distributed energy resource aggregations, would eliminating the Demand Response Opt-Out established in Order Nos. 719 and 719-A enhance clarity for market participants and prevent disputes regarding the eligibility of resource aggregations to participate in wholesale markets?

Clarity and consistency around rules governing participation of ARCs and distributed energy resource aggregators (DERAs) is urgently needed.

ISOs and RTOs around the nation are currently developing market participation rules for distributed energy resource (DER) aggregations under Order No. 2222. Confusion around how to treat component DR resources within a DER aggregation in market registration and participation models under the DR Opt-Out Rule, particularly within MISO and SPP, is both apparent and concerning. Currently, for example, SPP is planning to exclude all DR resources within a DER aggregation from participating in its wholesale market if the relevant RERRA has opted-out under the DR Opt-Out Rule.[114] Removal of the DR Opt-Out Rule would provide clarity to RTOs and ISOs and market participants currently navigating the Order No. 2222 compliance process, and enhance competition by enabling participation of all DER resources in wholesale markets.

Since 2009, DERs, which include small, flexible resources such as customer-sited batteries, electric vehicles, rooftop solar, and smart thermostats, have proliferated across the United States, primarily driven by customer demand, technology improvement, and falling prices. Aggregations of DR resources are the most common form of DERs participating in RTO/ISO wholesale electricity markets today. However, as the Commission recognized in

[114] Southwest Power Pool, Order 2222 Task Force Presentation, *Updated Registration Process* (July 2021) at Slide 2, *available for download at*: https://spp.org/spp-documents-filings/?id=253998.

Order No. 2222,[115] DERs have been largely left out of wholesale power markets.[116] As RTOs and ISOs implement Order No. 2222, it is therefore likely DR will form the foundation of many heterogenous DER aggregations. However, currently, under the DR Opt-Out Rule, RTOs and ISOs could require DERAs to exclude DR component technologies within DER aggregations from market participation. The DR Opt-Out Rule, thus, will likely raise costs and reduce competitive options for DERAs, system operators, and customers, by stripping DR of the ability to participate in heterogeneous aggregations. As noted by Advanced Energy Economy, without the ability of DR resources to participate, "DER aggregations may often not be able to achieve the scale or penetration in an area to form viable aggregations of distributed energy resources capable of effective competition in the wholesale market."[117]

Furthermore, DER aggregations, by design, operate across technologies as a single resource.[118] Splitting hairs in the treatment of DR within a DER aggregation under the DR Opt-Out Rule is discriminatory and inconsistent with the intent of Order No. 2222,[119] and also denies the reality of how DER aggregations function. DERAs operate DER aggregations by coordinating services across technologies within the DER aggregation as a single resource, thereby leveraging the flexibility afforded by coordinating component technologies across

[115] 172 FERC ¶ 61,247 at P 13.

[116] Wood Mackenzie (2020), United States Distributed Energy Resources Outlook: DER installations and forecasts 2016-2025E, https://www.woodmac.com/our-expertise/focus/Power--Renewables/der-outlook-us-2020/

[117] Advanced Energy Economy, Docket No. RM18-9-002, *Motion for Leave to Answer and Answer of Advanced Energy Economy and Advanced Energy Management Alliance* (filed May 8, 2021) at P3.

[118] Advanced Energy Economy, *FERC Order No. 2222 and the Use Cases It Can Unlock* (June 2021), *available at:* https://www.aee.net/aee-reports/ferc-order-no.-2222-and-the-use-cases-it-can-unlock

[119] 172 FERC ¶ 61,247 at P 103. (The Commission has stated that it will evaluate each RTO/ ISO Order No. 2222 proposal submitted on compliance to determine "whether it meets the goals of this final rule to allow distributed energy resources to provide all services that they are technically capable of providing through aggregation.")

multiple locations.[120] The perverse result is that the DR Opt-Out Rule will not only prevent DR aggregations from participation in wholesale markets but will also preclude many DER aggregations (if they include DR) from participation as well.

Treating DR resources within heterogenous DER aggregations under Order No. 2222 in such a manner, as a direct result of the DR Opt-Out Rule, is inconsistent with the principle that market rules should be fuel agnostic and technology-neutral, and interferes with the Commission's responsibility to ensure that wholesale rates are just and reasonable, and not unduly discriminatory. In conclusion, removal of the DR Opt-Out Rule would provide much-needed consistency and clarity to both ARCs and aggregators of DERs, as well as market operators currently navigating Order No. 2222 stakeholder compliance processes, all of which supports the Commission taking swift action to remove the DR Opt-Out Rule.

Q7) Is there any evidence to suggest that removing the Demand Response Opt-Out would result in additional demand response resources participating through aggregations in RTO/ISO markets? Similarly, is there any evidence to suggest that removing the Demand Response Opt-Out would result in additional demand response services or flexibility to address system needs? If so, are there ways to quantify these benefits to RTO/ISO markets? Do the benefits of permitting increased third-party demand response aggregations in RTO/ISO markets exceed those provided by utilities bidding demand response into such markets?

Ample evidence suggests removal of the DR Opt-Out Rule will support increased participation by DR resources in wholesale markets, enabling expansion of utility programs as well as non-utility DR and DER aggregation resource offerings. Where RERRAs have enacted laws and rules preventing ARCs from participating in wholesale markets under the DR Opt-Out Rule, this often represents a complete barrier to entry for DR resources into wholesale markets. Removing the DR Opt-Out Rule would enable these additional DR resources and ARCs to

[120] C-Power, *State of Demand-Side Energy Management, Volume III* (2021) at P100, *available at:* https://cpowerenergymanagement.com/demand-side-2021-webinar-series/.

compete in the RTO/ISO markets they are currently locked out of.[121] As described in PIO responses above, a significant number of RERRAs have banned ARCs from participating in wholesale markets. Currently, at least 13 state RERRAs covering large areas of both the MISO[122] and SPP[123] footprints, as well as smaller areas of PJM[124] have enacted restrictions and bans on ARC participation in wholesale markets. Most were enacted around 2009 or shortly thereafter, subsequent to the Commission's decision on rehearing in Order 719-A.[125] Many of these bans were initially framed as temporary, to allow for further deliberation at a later date.[126] However, more than a decade later, many remain in effect.

An analysis of EIA Form 861 (2019) retail sales data for large utilities y[127] in MISO suggests that within MISO alone, approximately *15 million customers*, representing $39.9 billion

[121] PIOs were able to confirm that at least thirteen state RERRAs have "opted out" of allowing retail customers to directly participate in wholesale markets through aggregators under the DR Opt-Out Rule: Arkansas, Iowa, Indiana, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Mississippi, North Carolina, North Dakota, South Dakota, and Wisconsin.

[122] Currently, ARCs that are not acting on behalf of a load serving entity (LSE) utility are expressly banned in 12 of the 15 states in which MISO operates, including Arkansas, Iowa, Indiana, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, North Dakota, South Dakota, and Wisconsin.

[123] At least 7 of the state RERRAs in which SPP operates have state laws or state public utility commission orders that restrict ARC participation in wholesale markets: Arkansas, Iowa, Louisiana, Missouri, North Dakota, and South Dakota.

[124] 4 PJM state RERRAs have opted out: Indiana, Kentucky, Michigan, and North Carolina,

[125] *See* Docket EL21-12-000, *Compliant of Voltus, Inc.* (Oct. 20, 2020) Centolella, Ex. A at Appendix B; *see also* State Opt-out Chart, Ex. C.

[126] Missouri Public Service Commission, Docket EW-2010-0187, *Order Temporarily Prohibiting the Operations of Aggregators of Retail Customers* (Effective March 31, 2010). In case EW-2010-0187, the Commission issued an 'Order Temporarily Prohibiting the Operation of Aggregators of Retail Customers'. In that order, the Commission determined that "Demand response load reductions of customers of the four Missouri electric utilities regulated by the Commission are prohibited from being transferred to ISO or RTO markets directly by retail customers or third-party ARCs." *Available at:* https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936187165 (last accessed July 18, 2021).

[127] Defined as utilities with greater than 4 million MWh annual retail sales.

and 419 million MWh in annual retail sales are within the service territories of large utilities that have opted out and therefore currently locked out of participation in the wholesale markets through competitive aggregators under the DR Opt-Out Rule. Furthermore, it is important to recognize that the DR Opt-Out Rule continues to present a looming risk to ARCs and DR participation across all wholesale markets, including where a RERRA has not opted-out. Removing the DR Opt-Out Rule would thus benefit all RTOs/ISOs, providing much-needed certainty and clarity to wholesale markets nationwide.

III. CONCLUSION

As detailed above, given the rapidly changing resource mix, widespread electrification, and greater customer resilience needs created by extreme weather events, a significant expansion of DR in the wholesale markets is essential. Removing the DR Opt-Out Rule is a long overdue step to expand the opportunities for innovation and opportunities for DR participation in the RTO/ISO markets. The PIOs therefore urge the Commission to begin a rulemaking that undoes Order 719's RERRA opt-out provisions.

Respectfully Submitted,

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Comments of Public Interest Organizations