

Enabling Third-Party Aggregation of Distributed Energy Resources

Report to the Public Service Commission of Arkansas

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Table of Contents

Disclaimer	2
Introduction	2
Statement of the Scope of Work	4
A. Description of grant parameters	4
B. Summary of Commission's charge to RAP	5
I. Overview of DER Aggregation	5
A. Definition of DER and status of deployment in US and Arkansas	5
B. Definition and benefits of aggregation	10
C. Options for aggregation and pros and cons of the options	13
D. Status in MISO states, and examples of where aggregation has been practiced outside MISO	18
II. Bidding Aggregated DR and DER into the MISO Market	20
III. Aggregation of DERs by Entergy Arkansas	23
A. Demand Response Programs	23
B. Discussion of AMI rollout	24
IV. Regulations for Third-Party Aggregators	25
A. Certification of Aggregators - Scope of Authority	25
V. Performance Incentive Metrics to Encourage Third-Party Aggregation	28
A. Measures – Identification of Commission Policy Objectives	28
B. Metrics	29
C. Establishment of Baseline	34

D. Considerations in Developing Targets	35
E. Incentives and/or Penalties	35
F. Potential Structures for the Performance Incentives	36
VI. Functional Separation and Codes of Conduct for Energy	39
A. Rationale behind Functional Separation and Creation of Codes of Conduct	39
B. Functional Separation	41
C. Codes of Conduct	43
VII. Conclusions	47
Appendix A: Certification of Aggregators of Retail Customers	49

Disclaimer

This paper was prepared at the request of the Arkansas Public Service Commission (PSC, the Commission). It is meant as informational, and the views and opinions expressed herein do not necessarily represent the views of the PSC.

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Introduction

In passing Act 1078 of 2013¹ (the Act) the Arkansas General Assembly articulated a state policy authorizing the Commission to “establish the terms and conditions for the marketing, selling, or marketing and selling of demand response by electric public utilities or aggregators of retail customers [ARCs] to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets.”

However, the Act makes it clear that ARCs are prohibited from selling demand response (DR) into wholesale electricity markets unless the Commission or the relevant governing authority finds it in the public interest. To date, the Commission has not issued such a ruling for Arkansas’ IOUs.

Although the Commission has not yet taken steps to implement this new authority, the statute potentially creates new opportunities for competitive service providers and customers in that the electric utilities in Arkansas are vertically integrated, and typically in such cases the opportunity for any form of competitive services is not available.² The execution of this policy falls within the

¹ AR Code Ann. § 23-18-1001 et seq.

² In response to the Federal Energy Regulatory Commission’s (FERC) Final Rule in Wholesale Competition in Regions with Organized Electric Markets, Order No. 719 and 719-A, FERC Docket No. RM07-19-001, 126 FERC ¶61,261 (2009), the Commission on August 18,

purview of the Commission, which has expressed an interest in further enabling the development and offering of DR, as broadly defined in the Act, which can serve to increase the reliability of the grid when strategically located, and reduce the need for new capacity.³

As defined in the Act, *demand response* means “a reduction in the consumption of on-peak or off-peak electric energy by a retail customer served by an electric public utility ... relative to the retail customer’s expected consumption in response to: (i) Changes in the price of electric energy to the retail customer over time; or (ii) Incentive payments designed to lower consumption of electric energy.”^{4,5} Given this definition, the Commission views the Act as consistent with its establishment of a docket originally opened in 2016 to investigate policies related to renewable distributed generation (DG), as amended in November 2017 to expand the investigation to “explore Distributed Energy Resources (DERs) and data access issues as well as questions that touch on matters that may affect other utilities, customer groups, and third parties that may have an interest in accessing customer data and integrating DER into the electric grid.”⁶ In that order, the Commission stated that it “considers DERs to include (but not be limited to) energy efficiency resources (EE), demand response (DR), smart thermostats, renewable resources and distributed generation (DG), including solar and wind technologies, storage technologies, including batteries and water heaters, and electric vehicles (EVs), all of which may be enabled, enhanced, and integrated into the grid by implementation” of advanced metering infrastructure (AMI).⁷

Among their numerous benefits, DERs can be a key contributor both to reducing high-cost peaking capacity and providing retail customers with an opportunity to reduce energy consumption and utility bills. Thus, the Commission is seeking to implement policies that remove barriers to entry for aggregators of DERs, encourage customer participation—which is the key to the success of DERs—and also incentivize utility cooperation and support. As permitted under the Arkansas statute, ARCs can thus participate through the sale of DER services to the incumbent utility, or, if the Commission makes a public interest finding, they can participate in the Southwest Power Pool

2009, established Docket No. 09-090-U to consider its regulatory authority over demand response (DR), which the Commission defined as a subset of Sustainable Energy Resources pursuant to Order No. 1 in Docket No. 08-144-U. The Commission thus opened a formal process for the purpose of considering the impact of FERC’s Orders on the authority of the Arkansas Commission, on the Arkansas jurisdictional public utility members of the Southwest Power Pool (and Midcontinent Independent System Operator, by later Order No. 7 in Docket No. 09-090-U), and upon their jurisdictional retail electric customers. The Commission initially directed the parties to that docket to file legal briefs addressing the Commission’s authority to permit ARCs to bid DR into wholesale markets, but in light of pending rehearing of ARCs matters at FERC, by Order No. 5 on December 18, 2009, extended the filing dates and later, in light of the enactment of Arkansas Act 1078 granting the Commission authority to regulate ARCs by Order No. 7 on November 13, 2013, suspended altogether the procedural schedule. Order No. 7 is the last substantive order in Docket No. 09-090-U.

³ As discussed below, the legislation mentions demand response, but the concepts and policies embodied in the legislation are more expansive so as to include distributed energy resources in order to achieve the legislative intent.

⁴ AR Code Ann., Section 23-18-1002(2)(A).

⁵ The statute contemplates reductions in both on-peak and off-peak consumption, which illustrates a desire to go beyond demand response programs which typically address only on-peak demand. Other Distributed Energy Resources, such as those defined in the Commission’s Docket No. 16-028-U, address either or both on-peak and off-peak usage as contemplated by the General Assembly. Therefore, it is entirely appropriate to address aggregation in the context of applying to all DERs.

⁶ Arkansas Public Service Commission, Docket No. 16-028-U, *Order No. 5 on November 9, 2017*, at 1. Retrieved from: http://www.apscservices.info/pdf/16/16-028-U_97_1.pdf

⁷ Id. footnote 6.

(SPP) and Midcontinent Independent System Operator (MISO) markets as they exist or may evolve. As this paper will discuss, even if the Commission authorizes ARCs to offer DERs into these regional transmission organizations (RTOs), the opportunity may be minimal at present due to a number of factors. These factors include the barriers that make these transactions costly and difficult, the fact that SPP does not currently have a capacity market, and that MISO has so much excess capacity that the price for DER services is too low for it to be economically viable at this time for an ARC. This paper will nevertheless explore issues that need to be addressed within the RTOs to create a market once prices reach a competitive threshold that makes DERs feasible in wholesale electricity markets.

The interest around the country in performance-based regulation (PBR) has led to a steady shift in thinking about traditional regulation. More commissions are taking the first steps of exploring whether to provide utilities incentives (and in some cases, penalties) based on their performance with respect to a particular commission goal or public policy directive. In some cases, commissions have started with metrics to simply report on utility activity toward clearly delineated Commission goals. The goals of the Arkansas Commission revolve around the successful implementation of aggregated DERs as set forth in Act 1078 and the expansion toward a modernized grid through the deployment of DERs pursuant to Commission order in Docket No. 16-028-U. Further, as AMI is adopted in the state, the goals could include rate designs that better align cost with causation. This paper will also explore some of the performance incentive metrics that can either be reporting goals to create a base of knowledge and transparency, or monetary metrics that attach an incentive or penalty for achieving or not achieving specific targets. This paper will focus on suggested metrics linked to achieving outcomes related to DERs and encouraging ARCs.

In creating a regulatory environment for ARCs to participate, other issues arise, such as a code of conduct in the event the utility is permitted to compete with ARCs for DER services. A code of conduct is critical to ensure that a fair and robust market is created so that ARCs can compete and customers can have an array of competitive options.

Finally, with the advent of ARCs, a key issue that arises is the level of Commission regulation. This paper discusses the regulation of terms and conditions of service, but stops at discussing price regulation, which is not necessary when a competitive market exists. Draft model regulations for the certification of ARCs are also included. This is an important consumer protection to ensure that those entities doing business in Arkansas and interacting with the public have the financial and technical capability to perform.

Statement of the Scope of Work

A. Description of grant parameters

The Lawrence Berkeley National Laboratory grant requests that RAP "provide technical assistance to state public utility commissions focused on quantitative financial analysis of incremental changes to cost of service regulation." The work will largely focus on alternative rate-making and regulatory approaches (e.g., net energy metering alternatives, revenue

decoupling) and financial incentives (e.g., performance incentives).

B. Summary of Commission's charge to RAP

As a result of utility interest in AMI and related questions that arose in connection with these proceedings, the Commission elected to open Docket No. 16-028-U, in order “to explore Distributed Energy Resources (DERs), and data access issues as well as questions that touch on matters that may affect other utilities, customer groups, and third parties that may have an interest in accessing customer data and integrating DER into the electric grid.”⁸ It is the Commission's intention to “collaboratively develop comprehensive recommendations regarding the provision of customer data to third parties, integration of DERs into the grid, and demand aggregation by third parties.”⁹ The Commission amended the earlier scope to “substitute ‘Distributed Energy Resources’ for ‘Renewable Distributed Generation.’ The Commission further expands the subject matter of this Docket to broadly collect information to consider whether any change is warranted in the Commission's policies related to DERs.”¹⁰

As a consequence, the Commission has requested that RAP provide the following information in a report to guide the Commission:

- Brief overview of DER aggregation: benefits, pros and cons of different aggregation options, status of aggregation in other MISO states and elsewhere;
- Pricing and tariff options for Entergy Arkansas, Inc. (EAI) that address DERs;
- Regulations and certification for third-party aggregators;
- Performance incentive mechanisms to encourage third-party aggregation; and
- Functional separation and codes of conduct for EAI.

I. Overview of DER Aggregation

A. Definition of DER and status of deployment in US and Arkansas

The term *distributed energy resource* (DER), as used throughout this report, can encompass a variety of energy resources that reside on the distribution system, typically behind the [customer's] meter (BTM). As noted above, this is consistent with the Arkansas Commissions' interpretation of the charge of Act 1078 of 2013. As such, and consistent with many other states, energy efficiency, demand response, distributed generation, and distributed storage systems are all considered DERs

⁸ Arkansas Public Service Commission, Docket No. 16-028-U. Retrieved from: http://www.apscservices.info/pdf/16/16-028-U_97_1.pdf.

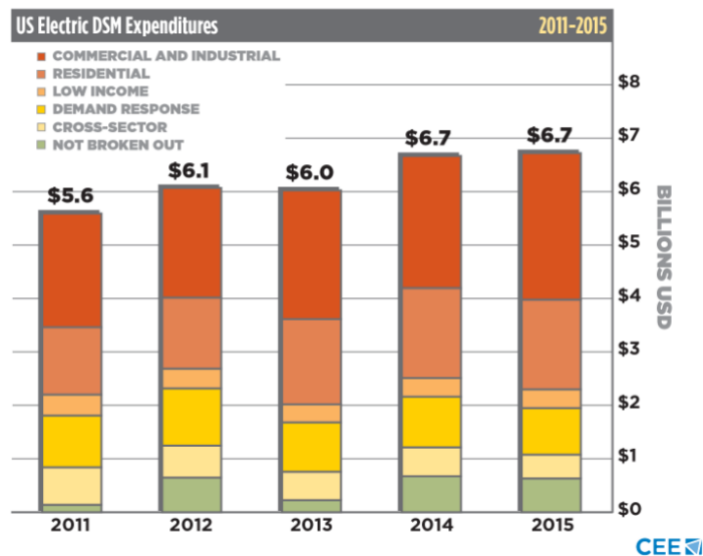
⁹ Arkansas Public Service Commission, Docket No. 16-028-U.

¹⁰ Arkansas Public Service Commission, Docket No. 16-028-U.

in this report. Some states exclude EE from their definition of DER, while others add EVs to the list. Arkansas includes both. Controllable loads, such as electric water and space heating loads, can also be managed as a DER that combines some of the attributes of distributed storage and more traditional load-shed DR¹¹. Each type of DER can provide some combination of energy, capacity, and ancillary services while reducing the energy costs of participants (i.e., those customers who own or control a DER). In many cases, DERs can provide grid services at a lower cost to electric utilities and non-participants than procuring the same services from traditional supply-side resources.¹²

The deployment of DERs has grown rapidly in recent years. The Consortium for Energy Efficiency (CEE) estimates that electric utility investment in EE and DR programs grew by more than a billion dollars from 2011 to 2015 (Figure 1).¹³ Installations of residential and non-residential BTM solar photovoltaic (PV) systems grew by 10 GW over the same time period (Figure 2).¹⁴

Figure 1. Demand-Side Management in the United States



¹¹ The statutory definition of DR can be construed to encompass traditional load-shed DR as well as other DERs, since the statute speaks not only to load reductions on the utility system, but also reductions in on-peak or off-peak energy consumption.

¹² Lazard's Levelized Cost of Energy Analysis, Version 8.0, indicates that EE provides energy at a lower cost than any other resource. Refer to: https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf. DR resources have proven to be consistently competitive as capacity resources in the forward capacity markets operated by PJM and ISO-New England, as noted later in this paper. Examples of DERs providing ancillary services at competitive rates are only beginning to emerge. Battery energy storage systems, for example, have in a few cases offered frequency regulation services in competitive markets.

¹³ Consortium for Energy Efficiency (2016). State of the Efficiency Program Industry. Retrieved from: <https://library.cee1.org/content/cee-2016-state-efficiency-program-industry>. Comparable data for 2016 and 2017 expenditures are not yet available.

¹⁴ SEIA/GTM Solar Market Insight reports. Note that the figure shows annual capacity additions, not cumulative installed capacity.

Figure 2. U.S. Solar PV Installations, 2010-2016

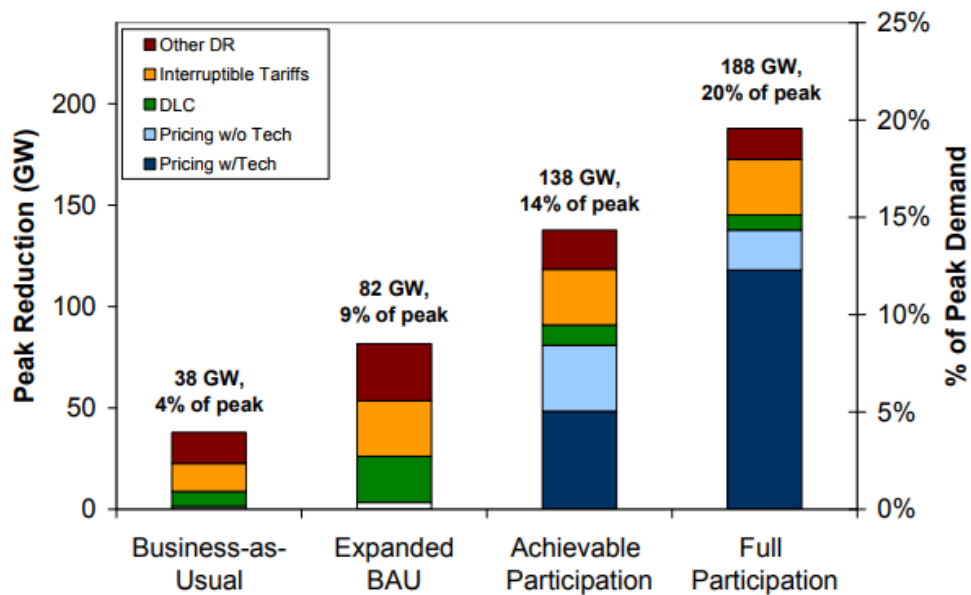
Nevertheless, adoption of DERs has been uneven among the states and significant untapped potential for cost-effective DER deployment remains. For example, EE potential studies routinely identify “achievable potential” savings at levels that are much lower than what is technically cost-effective (“economic potential”).¹⁵ Potential studies for DR are less common, but those that have been published generally show considerable untapped potential for cost-effective load shedding. For example, in 2009 the Federal Energy Regulatory Commission (FERC) published *A National Assessment of Demand Response Potential*, which showed that achievable DR potential could be more than 50 GW higher in 2019 than the amount expected under a “business as usual” scenario (Figure 3).¹⁶ Furthermore, a recent study for the California Public Utilities Commission suggests

¹⁵ Navigant Consulting, Inc. (2015). Arkansas Energy Efficiency Potential Study. Retrieved from: http://www.apscservices.info/pdf/13/13-002-U_212_2.pdf. This study, prepared for the Arkansas PSC, found economic potential to be greater than 15% of annual electricity sales, while achievable potential was about 8% (cumulative through 2025) of annual electricity sales.

¹⁶ Federal Energy Regulatory Commission (2009). *A National Assessment of Demand Response Potential*. Retrieved from: <https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf>.

that the load-shedding value of DR is but one source of potential value, and controlling loads to shape, shift or “shimmy” (i.e., dynamically adjust) demand will become increasingly valuable as the penetration of variable renewable generation grows.¹⁷ In fact, the study found that the future value of load shedding will be almost entirely derived from avoiding local peaks or transmission constraints on the *distribution* system, while load shaping, shifting, and shimmying will provide new sources of currently untapped value at the independent system operator (ISO) level.

Figure 3. U.S. Demand Response Potential by Program Type

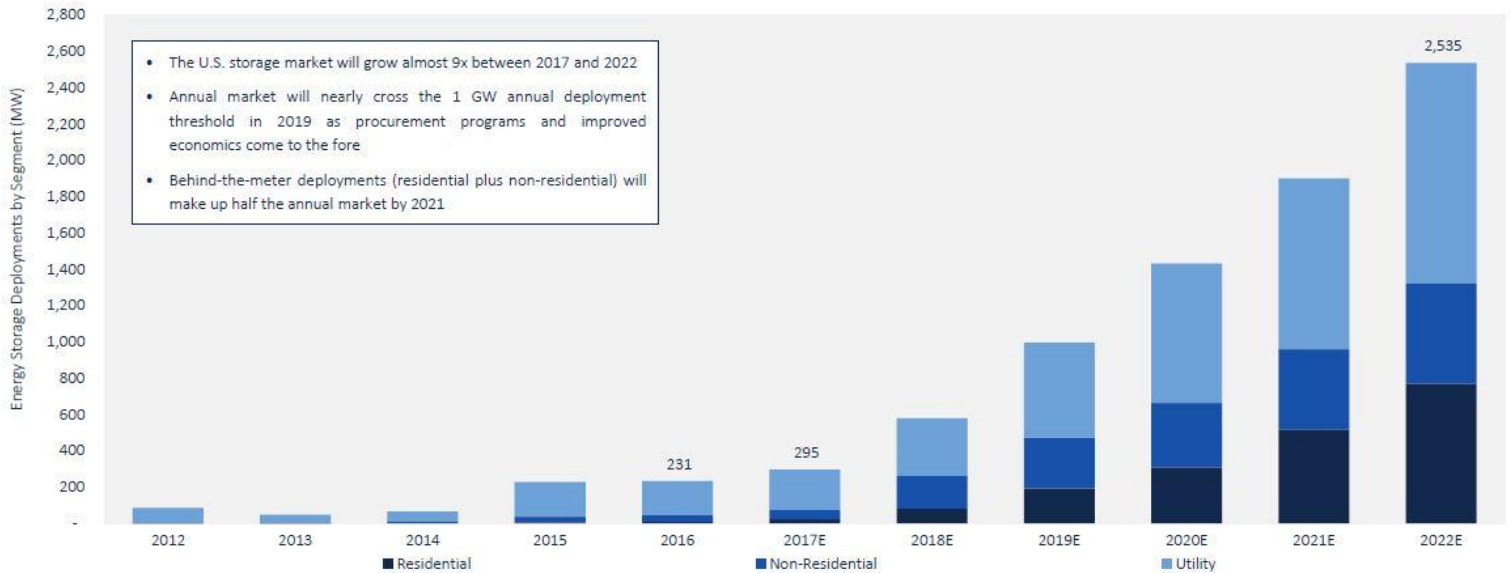


Looking at the potential for other DERs, industry analysts project substantial future cost declines for PV systems, battery energy storage systems, and EVs. These expected cost declines could lead to exponential growth in DER deployment in the decades ahead. Energy storage deployments, for example, could grow to almost nine times their current level in the next five years, with BTM storage growing to comprise half the total storage market (Figure 4).¹⁸

¹⁷ Lawrence Berkeley National Laboratory (2016). 2015 California Demand Response Potential Study. Retrieved from:

<http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541>.

¹⁸ GTM Research (2017). U.S. Energy Storage Monitor. Retrieved from: <https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.sNa=IKw>.

Figure 4. U.S. Annual Energy Storage Deployment Forecast, 2012-2022E (MW)

Arkansas has seen considerable deployment of some types of DERs in recent years, and has risen from a “late starter” on DER installations at the beginning of the decade to the middle third among US states – or better – in many respects. Looking at different types of DERs separately:

- EE – According to the 2017 American Council for an Energy-Efficient Economy scorecard,¹⁹ in 2016 Arkansas utilities collectively achieved net incremental savings from electric EE programs equal to 0.7% of 2016 retail sales. This placed Arkansas 22nd among states on electric EE savings. It should be noted that EAI reported achieved net savings in 2016 equal to 1.2% of retail sales, considerably higher than the statewide average and higher than the PSC-imposed target of 0.9%.²⁰
- DR – In Form EIA-861 data reported by utilities to the US Energy Information Administration,²¹ Arkansas utilities reported 227 MW of actual peak demand savings in 2016 from DR. Arkansas ranked 17th among all states on reported DR savings. Arkansas utilities contributed 1.9% of all reported savings in the United States. Given that Arkansas has less than 1% of the US population, this suggests the state is getting significantly better-than-average results from its current DR efforts.
- DG – The National Renewable Energy Laboratory’s Open PV Project database includes

¹⁹ Berg, W., Nowak, S., Kelly, M., Vaidyanathan, S., Shoemaker, M., Chittum, A., DiMascio, M., and DeLucia, H. (2017). The 2017 State Energy Efficiency Scorecard. American Council for an Energy-Efficient Economy. Retrieved from: <http://aceee.org/research-report/u1710>.

²⁰ Entergy Arkansas, Inc., (2017). In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Energy Efficiency Programs and Energy Efficiency Cost Rate Rider. Docket No. 07-085-TF. Retrieved from: <http://www.apscservices.info/EEInfo/EEReports/Entergy%202016.pdf>

²¹ US Energy Information Administration (2017). Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files. Retrieved from: <https://www.eia.gov/electricity/data/eia861/>.

239 PV projects totaling 4.85 MW in Arkansas. This is obviously just a snapshot in time, and the number constantly grows. This puts Arkansas 32nd among the states in number of systems deployed and 33rd in terms of installed capacity.²²

- Storage – The US DOE Global Energy Storage Database lists only one energy storage project in Arkansas, a pumped storage hydro facility.²³ Comprehensive data on distributed energy storage systems are not publicly available, but there are probably a very small number of these systems installed in Arkansas today.
- EVs – US DOE compiled data on plug-in EV registrations by state in 2016.²⁴ The data indicate that Arkansas had 0.21 EVs registered per 1,000 people. Only one state had fewer registered EVs per capita.

Based on past potential studies and achievement seen in other states, Arkansas has enormous technical potential and probably considerable “achievable” potential for *increased* DER deployments. Some of the policies falling under the jurisdiction of the PSC, including rules relating to DER aggregation, can significantly influence the rate of new DER deployments.

B. Definition and benefits of aggregation

The primary focus of this paper is on third-party aggregation of DERs, which is discussed below. *Third-party* refers to any entity other than the electric utility and the utility’s individual customers. *Aggregation* refers to the assembly of a portfolio of DERs from multiple customers that can be managed collectively to provide energy, capacity, or ancillary services. For example, the DR potential of multiple industrial customers or thousands of residential air conditioners can be managed as an aggregated resource, providing significant peak demand reductions, frequency response services, etc.

FERC Order 719 (2008) established rules²⁵ requiring each RTO and ISO to amend its tariffs as needed to allow for participation of ARCs in organized wholesale electricity markets, unless such participation is limited by state and local regulatory authorities:

“Aggregation of retail customers. Each Commission-approved independent system operator and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers’ demand

²² The Open PV Project (undated). Open PV State Rankings. Golden, Colorado: National Renewable Energy Laboratory. Retrieved from: <https://openpv.nrel.gov/rankings>.

²³ Sandia National Laboratories (undated). DOE Global Energy Storage Database. Retrieved from: <https://www.energystorageexchange.org/>.

²⁴ Office of Energy Efficiency and Renewable Energy (2017). California Had the Highest Concentration of Plug-In Vehicles Relative to Population in 2016. Washington, DC: US Department of Energy. Retrieved from: <https://energy.gov/eere/vehicles/articles/fotw-1004-november-20-2017-california-had-highest-concentration-plug-vehicles>.

²⁵ 18 CFR 35.28(g)(1)(iii).

response to be bid into organized markets by an aggregator of retail customers. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers.”

MISO's tariffs comply with FERC Order 719 and explicitly allow for ARC participation. MISO defines ARC²⁶ as follows:

“an Aggregator of Retail Customers (ARC) is an MP [market participant] sponsoring one or more DRRs [demand response resources] or LMRs [load modifying resources] provided by customers that it does not serve at retail. An ARC can, but need not, be an LSE [load serving entity] sponsoring a DRR or LMR that is the retail customer of another LSE.”

In this paper, we will consider not just the aggregation of DR resources by ARCs, as is currently authorized in Arkansas statutes, but also the potential future aggregation of other types of DERs by third parties. MISO's definition of LMR encompasses only DR and BTM generation. FERC's current rules do not preclude RTOs and ISOs from allowing other DERs to be aggregated, but do not require the RTOs and ISOs to allow it. However, in practice, there are currently relatively few examples of any type of DER other than EE and DR being aggregated for participation in the wholesale markets, and there are several significant barriers. This could change. In late 2016, FERC released a Notice of Proposed Rulemaking (NOPR) – called by many the “Storage NOPR”²⁷ – which solicited public comments on possible reforms to RTO and ISO market rules that would remove barriers to the participation of electric storage resources and DER aggregations in organized wholesale electricity markets. The comment period for that NOPR closed in February 2017, but FERC has yet to take any final action.

The principal benefit of DER aggregation from the system operator's perspective is that it enhances and expands the gains that individual DERs can potentially provide to the grid. The principal benefit from the customer's perspective is that aggregation expands the opportunities to extract economic value from DERs. Without aggregation, individual DERs can *theoretically* provide energy, capacity, and ancillary services at the ISO/RTO level or the distribution level, but in practice most of that potential will go unrealized due to a variety of barriers, including:

- Minimum thresholds for participation in ISO/RTO markets are high – To participate in the current MISO markets, load-modifying resources must be capable of shedding at least 1 MW of load and energy resources must be capable of generating at least 5 MW. Given

²⁶ Midcontinent Independent System Operator, Inc. (2017). Business Practice Manual 001 (Market Registration). Retrieved from: <https://www.misoenergy.org/legal/business-practice-manuals/>.

²⁷ Federal Energy Regulatory Commission, Docket Nos. RM16-23-000 and AD16-20-000, Notice of Proposed Rulemaking on November 17, 2016. Retrieved from: <https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf>.

these thresholds, very few individual DERs are large enough to participate and capture market value.

- ISO/RTO market rules and procedures are complex – The rules and procedures governing wholesale electricity markets are extraordinarily complex and constantly evolving. Any company or customer wishing to individually participate in these markets will need to invest significant time in merely learning the rules and eligibility requirements. Once those are understood, the registration paperwork for becoming a market participant is extensive. And finally, participating in the markets on a daily basis will also require human resources. In short, the transaction costs of market participation are substantial and will only be practical for large industrial and commercial customers who can afford to dedicate professional staff to this activity. This is why the participation of aggregators can be transformative to the wholesale and retail electricity markets.
- Wholesale market revenues may be too low to justify the transaction costs – Even if a DER is big enough to participate in ISO/RTO markets, and the customer or company controlling the DER is sophisticated enough to register and participate, the value proposition is far from certain. For example, the MISO markets currently have operating reserves far in excess of resource adequacy requirements. This means that load curtailments are rarely needed, and DR resources can expect very little market revenue. It also means that wholesale energy and capacity prices are consistently low, which reduces the revenue that DERs capable of injecting energy might hope to capture. As a practical matter, the transaction costs for market participation by a single customer (described above) will typically exceed any market revenues that could potentially be gained under current conditions.
- Utilities (and system operators) may not have “visibility” of DERs or the ability to dispatch/control them. To capture some of the potential value of DERs at the retail distribution level, a utility needs to know what types of DERs have been installed, where they are, what distribution system services they can potentially provide, and their operational status. The utility will also need the ability to control the DERs or send dispatch signals to whoever controls the DERs in order to provide distribution system services when and where they are most needed (and most valuable). And finally, the utility will need mechanisms for compensating DER owners who provide such services. The essential problem is that a utility will need to have enough DER capacity under its control to provide meaningful distribution system services, but identifying, controlling, and compensating individual unaggregated DERs may not be cost-effective.

Aggregation of DERs can overcome most of these barriers. Acting on behalf of many customers who have small DERs, an aggregator can easily meet the size thresholds for market participation and learn market rules and procedures. Aggregation can also bring visibility, direct control, and the ability to plan for and dispatch DERs as grid resources. For example, by aggregating and controlling the demand from thousands of air conditioning units, a virtual capacity resource is created that can shed load in response to system emergencies or critical peaks at the wholesale market level or the distribution system level. The impact of any one air conditioner would be trivial

and of no value to grid operators, but the collective value can be substantial. An aggregation of EV charging stations can be controlled for similar purposes, or to arbitrage wholesale energy prices. In either case, shedding or shifting demand helps maintain reliability and is often less expensive than dispatching a load-following or peaking resource. Compensating a single aggregator is also simpler and less expensive for a utility than compensating numerous individual DER owners.

In summary, DER aggregation can potentially unleash all of the following benefits, some of which are enhancements to the benefits provided by individual DERs and some of which are possible only through aggregation:

- Allows small resources to provide grid services when and where they are needed;
- Allows small resources to participate in wholesale markets, potentially lowering market clearing prices while also bringing revenue to DER participants;
- An aggregation of DERs can meet the availability requirements for wholesale market participation without each DER having to individually meet those requirements;
- Creates economies of scale and lower transaction costs for wholesale electricity market participation;
- Enhances reliability;
- Reduces wholesale energy costs for all customers;
- Lowers participants' net costs; and
- Makes DERs more cost-effective and accelerates deployment of clean energy resources.

C. Options for aggregation and pros and cons of the options

There is a wide range of options for allowing DER aggregation and capturing the potential benefits of aggregation. The policies adopted by retail regulatory authorities (i.e., state utility commissions, and the governing bodies of municipal and cooperative electric utilities), along with the market rules adopted by RTOs and ISOs, will strongly influence which options are possible in any jurisdiction and which will attract the attention of ARCs and customers. In this section, we will look at key questions that regulators must consider when enabling aggregation (though not necessarily in the order we present them), and discuss the pros and cons of various options for DER aggregation.

One of the first key questions that will shape the options for aggregation is, *what types of DERs can be aggregated?* As noted above, MISO's definition of ARC encompasses DG and potentially other DERs, while the mandatory provisions in FERC Order 719 apply only to aggregation of DR. PJM Interconnection and ISO-New England explicitly allow aggregation of EE as a capacity resource. In practice, aggregation of any type of DER other than EE or DR remains rare in US wholesale electricity markets. Adopting a narrow scope for aggregation, limited only to DR, can simplify the development of wholesale market rules and procedures, as well as retail utility tariffs and programs. That is an advantage. However, the disadvantage of adopting such a narrow scope is that it

forges the potential benefits of aggregating other types of DERs. A narrow scope also precludes the possibility that combinations of different types of DERs can potentially create synergistic value. For example, recent research suggests that combining DR with distributed storage can be more valuable than the sum of the individual values of each type of DER.²⁸

A second crucial question for policymakers is *who may aggregate DERs?* DERs can be aggregated by utilities or by third parties.²⁹ The term *ARC*, as currently defined in Arkansas statutes and MISO business practices, excludes utility aggregation of DERs within their own service territory. But this does not mean that utilities cannot aggregate DERs within their own service territory – they just wouldn't be called ARCs. Each option has its advantages compared to the other option:

- Aggregation of DERs by ARCs can be customized to the needs of individual customers in a way that may not be possible when regulated utilities offer similar programs. ARCs can specialize in certain types of DERs (e.g., DR or storage) or certain grid services (e.g., emergency load reduction or frequency response), and they can partner with (or even be) equipment manufacturers that understand DER capabilities even better than utilities do. They can specialize in the administrative aspects of aggregation – i.e., customer acquisition and customer service – as a core business function rather than as a non-essential activity. All these factors may entice more participants to allow their DERs to provide grid services. Aggregation of DERs by ARCs also promotes competition in energy services and mitigates the potential abuse of monopoly utility advantages in providing energy, capacity, and ancillary services. ARCs can profit by bringing more and more DERs into electricity markets, whereas traditionally regulated utilities have incentives to discourage DERs (i.e., the throughput incentive and a rate-based investment bias). The need for oversight of ARCs by utility regulators is generally less than the level of oversight that is expected when utilities serve as aggregators, because regulators do not set or approve prices offered by third parties to participating customers.
- Utilities have different advantages as aggregators of DERs. To begin with, they are better informed and more in tune with distribution system needs and utility load requirements than third parties. They may also understand wholesale market rules and the interactions between various markets in a more complete way. Utilities are well positioned to compare the costs of DER aggregation to the costs of other resource options and thus to obtain the lowest total costs for system reliability. They also know their customer base better.

An important related question is, *should regulators allow ARCs to offer the services of aggregated*

²⁸ St. John, J. (2017). Stem and CPower to Combine Behind-the-Meter Batteries and Demand Response. Greentech Media. Retrieved from: <https://www.greentechmedia.com/articles/read/stem-and-cpower-to-combine-behind-the-meter-batteries-and-demand-response#gs.pYA8av0>.

In another example, the US Department of Energy funded a Community Solar Value Project that focused in part on identifying the synergistic value of combining community solar with DR and storage. Combining community solar with DR was found to lead to more effective voltage regulation than using either type of DER alone. Sena, S., and Hawkins, J. (2017) Community-Scale Solar Plus Thermal Storage and Demand-Response: A Modeling Study of Local Grid Benefits. Public Service Company of New Mexico. Retrieved from: http://www.communitysolarvalueproject.com/uploads/2/7/0/3/27034867/2017_09_28_pnm_grid_benefits.pdf.

²⁹ Technically, DERs can also be aggregated by customers themselves, but very few customers have the scale of DER deployment and the knowledge of utility and market rules that would be necessary for them to act as an ARC. Our discussion of ARCs will focus only on third-party aggregators, though we would not wish to preclude the possibility of customers serving as ARCs in those rare cases where it is feasible.

DERs in wholesale electricity markets, or only allow them to offer services to the local utility? Most of the discussion around third-party aggregation of DERs assumes that ARCs will bid DER services into wholesale electricity markets. This is certainly one option. But even though offering aggregated services to utilities may initially seem like a novel idea, it is actually quite common – it just usually isn't characterized as aggregation. For example, most of the utilities that offer EE programs to their customers work with third-party EE program implementers, who are essentially aggregators of EE that is offered to the utility but not directly to wholesale markets. The same is true for some DR programs that are managed by third parties on behalf of utilities. In Arkansas, EAI currently contracts with CLEAResult to administer ratepayer-funded EE programs and with Comverge to manage DR programs. Utilities that participate in organized wholesale electricity markets can adjust their load requirements to account for aggregated DERs, or the utility itself can bid the aggregated DERs into the wholesale markets as a resource. There are also examples of regulated utilities procuring DERs through competitive bidding processes in which aggregators are allowed to compete.³⁰

A variety of contentious issues have arisen in state utility commission dockets examining the question of whether to allow ARCs to bid directly into wholesale markets.³¹ Some of the issues and concerns can be briefly summarized here:

- Would ARCs fall within the state's definition of public utility, but operate without the full regulatory oversight (i.e., oversight of prices, terms, and conditions of service) applied to other public utilities?
- If utilities fulfill their obligation to procure adequate capacity to serve the full requirements of all their customers, and those costs are socialized across the rate classes, could that result in unfair rates or subsidies if some customers (through ARCs) can essentially sell their capacity reduction in the wholesale market and thereby, minimize their contributions toward paying for that capacity?
- Would allowing ARCs to bid into wholesale markets be a breach of the implied "regulatory compact" wherein utilities are granted an exclusive franchise and opportunity to recover all prudent costs and earn a reasonable return in exchange for providing universal service?
- Will ARCs cannibalize utility-administered DR programs, or supplement them? If the former, this might reduce the cost to ratepayers of administering DR programs, but would it also serve to privatize benefits that had previously been shared with utilities and non-participants?
- Could the activities of ARCs complicate or even undermine utility planning and resource

³⁰ Con Edison's Brooklyn Queens Demand Management program offers one such example: <https://conedbqdmauction.com/>. When the utility sought demand reductions via a competitive auction, the winning bids came from aggregations of DR and of battery storage systems.

³¹ Minnesota Public Utilities Commission, Docket No. E999/CI-09-1449, Order on April 16, 2013,

<https://www.edockets.state.mn.us/Efiling/edockets/searchDocuments.do?method=showPopup&documentId=%7B9DE70FBC-8E5C-42C4-8D43-E871305B2023%7D&documentTitle=20134-85762-01>; Public Service Commission of Wisconsin, Docket No. 5-UI-116, Order on October 9, 2009, <http://apps.psc.wi.gov/pages/viewdoc.htm?docid=121634>; Missouri Public Service Commission, Docket No. EW-2010-0187, Order on March 31, 2010, <https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935484458>.

acquisition decisions, increasing the risk of stranded assets? If so, what mechanisms can be deployed to minimize that risk?

- Would state regulators of retail electricity services cede oversight and authority to federal regulators of wholesale markets? Would complicated and contentious questions of jurisdictional authorities require adjudication?
- Will ARCs be selling services in wholesale markets that duplicate or are inconsistent with services that the retail utility is expecting to receive from the same DERs? What steps can be taken to avoid double counting of DER capabilities?

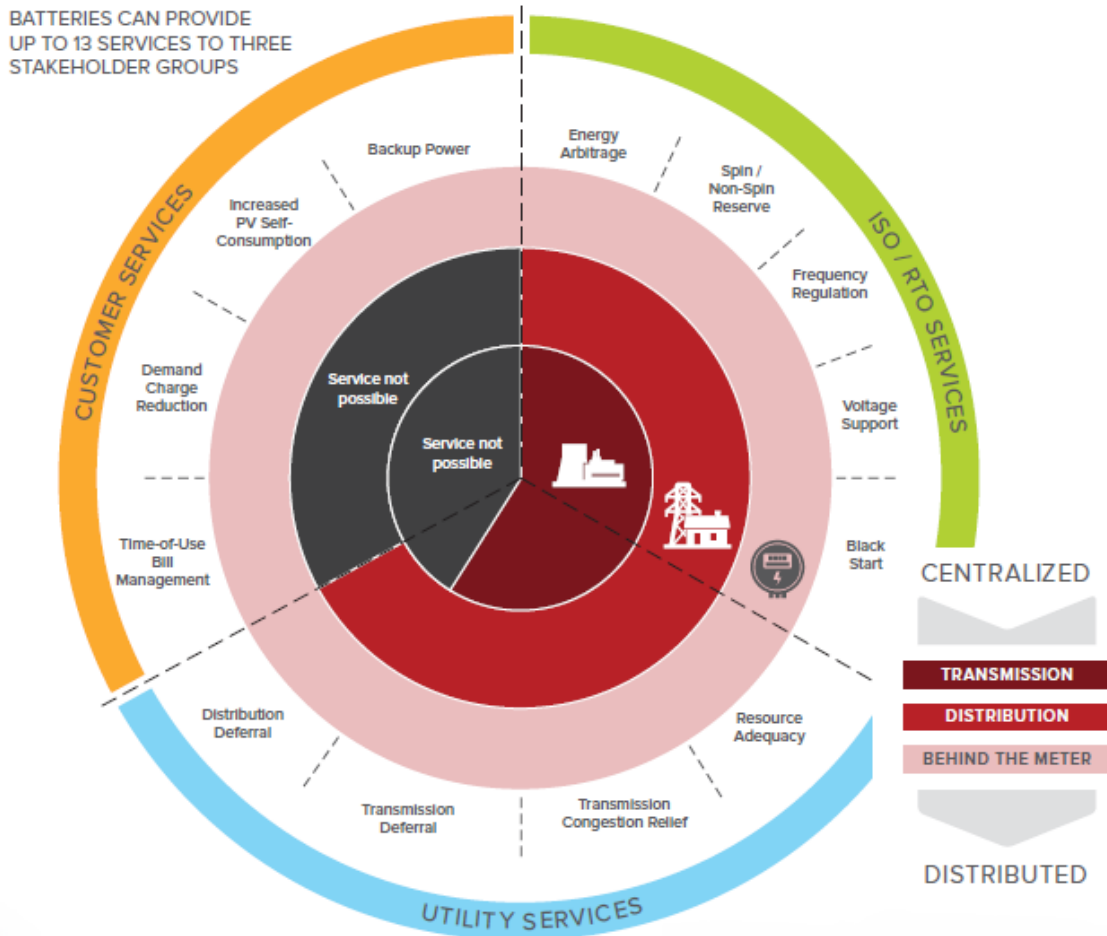
Allowing third parties to aggregate DERs and sell those services to utilities can capture many (but not all) of the benefits of ARCs, while avoiding most of the complications that arise with allowing ARCs to participate directly in wholesale markets. State regulators would need to evaluate these trade-offs before determining the best option for their state.

The next question to ask is, *what services will aggregated DERs be allowed to provide?* Broadly stated, the list of potential services includes energy, capacity, and ancillary services. Looking at a more detailed level, many options emerge. For example:

- Within the energy category, distributed storage systems and some controllable loads (e.g., electric water and space heating) can be dispatched as an aggregated resource in a form of price arbitrage. Those resources, controlled remotely by an aggregator, can be charged when energy is abundant and cheap (usually coinciding with low wholesale energy prices), and discharged when energy is scarce and expensive (high wholesale energy prices). This arbitrage value can be shared between the aggregator and the participants, or if a utility serves in the role of aggregator, participants and non-participants alike. Non-participants could benefit in any case through reduced market prices at times when system peak costs are rising. Aggregated DERs can also be dispatched on a locational basis to relieve transmission congestion and reduce transmission charges for all customers within the congested area. DERs that are not aggregated generally are too small to affect wholesale energy prices and cannot be dispatched in response to real-time wholesale prices.
- With respect to capacity, DERs can be used to reduce peak demand requirements of participants and thus reduce demand charges. The capacity value of aggregated DERs can also be applied to satisfy a utility's long-term resource adequacy requirements or to defer other infrastructure investments, and it can be bid as a resource in forward capacity markets where they exist. Dispatchable, aggregated DERs can also be managed to reduce the day-ahead and real-time load requirements for a utility or an entire wholesale market load zone, while unaggregated DERs cannot be dispatched in this manner and generally will not meet minimum size thresholds for participation in energy markets.
- Aggregated DERs can provide a full range of ancillary services, including frequency regulation, voltage support, spinning/non-spinning reserves, and black start capability. Without aggregation, individual DERs will generally be too small to participate in ancillary service markets, and in any event, won't be under the control of an entity that is aware of system needs and able to make use of the DER's capabilities.

Some DERs can provide a wide array of these potential benefits. For example, Figure 5³² shows the services that distributed storage systems can provide, based on where a system is installed on the grid. The dark red inner circle indicates the services potentially provided by storage systems installed on the transmission system, then the next circle out is for storage systems installed on the distribution system, and finally the pinkish circle is for BTM storage systems. The graph indicates that BTM storage can potentially provide all of the services indicated on the outer ring of the figure, while storage installed on the distribution system cannot provide customer services, and storage installed on the transmission system can't provide customer services or distribution deferral services.

Figure 5. Battery Services



Other DERs, such as EE, may offer only a limited (but valuable) set of benefits. Ultimately, state utility regulations and wholesale market rules will dictate which of the options are allowed, while the economic value to wholesale markets, participants, and aggregators will determine which of the

³² RMI (2015) The Economics of Battery Energy Storage. Retrieved from: <https://rmi.org/insights/reports/economics-battery-energy-storage/>.

allowed options are implemented. There is an obvious advantage to allowing aggregated DERs to provide all these potential services, or as many as possible. The advantage is that it maximizes the value of the DERs, incentivizes the deployment of clean energy, and reduces costs for participants and non-participants alike. The disadvantage is that regulations and market rules may need to be revised to allow such broad participation, the regulations and rules may become more complicated, and the need for oversight of aggregators will increase. For example, if aggregated DERs are relied upon for resource adequacy, the need to ensure that aggregators are genuinely capable of delivering capacity when and where it is needed becomes essential for reliability.

Finally, there is a range of options in terms of the possible models for aggregated DER participation in (and compensation from) wholesale markets. These “participation models” can differ in terms of the types of resources that are eligible, the qualification requirements, registration and information requirements, services each type of resource can bid into wholesale markets (e.g., energy, regulation, spinning or supplemental reserves, ramping, planning resource auction capacity, and emergency energy), and whether the resources are subject to “must offer” requirements.³³

The advantage of providing multiple participation models is that it creates different ways for aggregators to contribute valuable grid services and earn market revenues. Aggregators will then weigh the pros and cons of each model before deciding whether and how to participate in wholesale markets. The only drawback to having multiple models is that it complicates the market rules. However, decisions about participation models are made by the RTOs and ISOs, not by state regulators or policymakers. State officials only have to decide whether to allow aggregators in their state to bid resources into wholesale markets.

D. Status in MISO states, and examples of where aggregation has been practiced outside MISO

As of December 2017, Illinois is the only state within the MISO footprint that allows ARCs to directly participate in the wholesale market. This is not unexpected, since Illinois is also the only MISO state that allows retail competition in energy supply, but it is worth repeating that retail choice is not a prerequisite for allowing ARCs to participate in wholesale markets.

Although ARCs currently cannot directly participate in the MISO market outside of Illinois, this does not mean aggregated DERs are not participating. As previously noted, many utilities have DR programs (managed internally or by third parties under contract with the utilities), and those aggregated resources are sometimes bid by the utility into the MISO markets. In the 2016 State of the Market Report, MISO’s independent market monitor reports that more than 10 GW of aggregated DR and BTM DG resources have participated in the market in each of the past three years.³⁴ The vast majority of these resources have been bid into the market by utilities.

³³ This is a cursory treatment of a complex subject. Each ISO/RTO has unique participation models and market rules. For a more thorough treatment of MISO’s current participation models, see MISO’s Demand Response Primer and Training Guide at <https://cdn.misoenergy.org/Demand%20Response%20Primer118479.pdf>.

³⁴ Potomac Economics (2017). 2016 State of the Market Report. Midcontinent Independent System Operator, Inc. Retrieved from:

Looking ahead, the Organization of MISO States (OMS) is taking a leadership role on better integrating DERs into utility operations and the MISO wholesale market. OMS published a DER work plan³⁵ in June 2017, outlining its approach on DERs, and held a public workshop in August 2017.³⁶ The OMS work plan identifies two “key considerations” that relate specifically to the participation of aggregated DERs in MISO markets:

- Markets – market products in MISO were developed to accommodate existing resources in wholesale markets and utilization of the bulk electric system. Integration of significant amounts of DER will likely require new market products to enable non-discriminatory participation and properly monetize the value of DER.
- Pending federal policy development – FERC issued a Notice of Proposed Rulemaking in 2016 focused on how RTOs incorporate battery storage and DER aggregations into wholesale markets. OMS should be prepared for any potential federal policy proposal by proactively developing policy appropriate for the MISO region.

Some of the other RTOs and ISOs have seen greater market participation by ARCs and aggregation of DERs other than DR. A few examples serve to illustrate the point:

- The most recent Market Monitor Report for PJM indicates that more than 750 DR resources and 2 GW of capacity were registered in its “economic program,” on average, through the first nine months of 2017.³⁷ PJM’s economic program allows dispatchable DR resources to participate in the energy market and receive compensation at the locational marginal price for each MWh of curtailed energy. In addition, more than 5% of the annual capacity that cleared in PJM’s most recent forward capacity auction will come from aggregated EE and DR (Table 1).³⁸
- The California ISO (CAISO) recently created a new participation model for non-generator resources (NGRs) that is designed to accommodate any type of DER or combination of DERs that can quickly and repeatedly shift between consuming and injecting energy. This participation model is particularly helpful for enabling dispatchable storage resources to provide energy, reserves, and regulation services in the day-ahead and real-time markets. As of December 2017, CAISO has seen three stationary battery installations register as NGRs, and one aggregation of EVs with experimental “vehicle-to-grid” capabilities enabled (mobile batteries). This is in addition to aggregated DERs that are being registered in the CAISO market as DR resources that can modify consumption but not inject energy. CAISO

<https://cdn.misoenergy.org/2016%20State%20of%20the%20Market%20Report102526.pdf>.

³⁵ Organization of MISO States (2017). OMS Approach on Distributed Energy Resources. Retrieved from:

http://www.misostates.org/images/PositionStatements/OMS_DER_Overview_and_Work_Plan_Document.pdf.

³⁶ Organization of MISO States (2017). OMS DER Workshop: Retail Meets Wholesale. Retrieved from: <http://wpui.wisc.edu/wp-uploads/2017/07/DER-Workshop-Agenda-as-of-July-27.pdf>.

³⁷ Monitoring Analytics, LLC (November 2017). Quarterly State of the Market Report for PJM: January Through September. Retrieved from: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q3-som-pjm.pdf.

³⁸ PJM Interconnection (undated). 2020/2021 RPM Base Residual Auction Results. Retrieved from: <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx>.

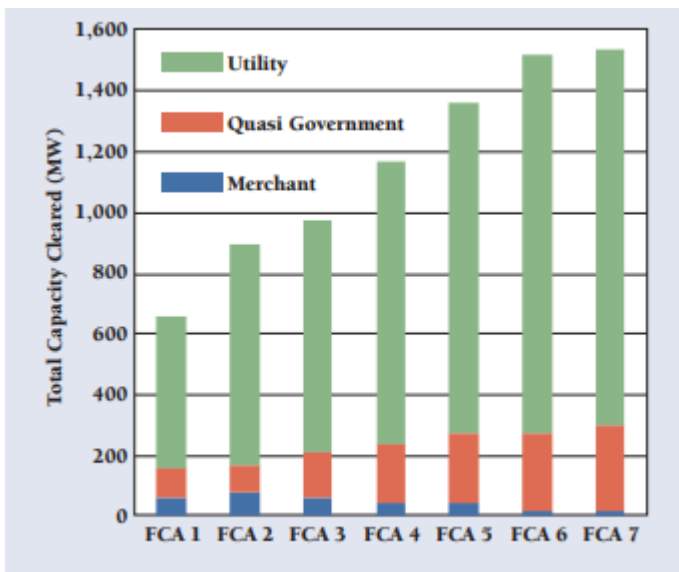
has also created a new category of market participant specifically for aggregators, which they call a DER Provider.

- In the ISO-New England forward capacity market, EE is allowed to be offered as a capacity resource. Although most of the EE that has cleared in the forward capacity auctions has been bid by utilities, some has been bid by merchant ARCs (Figure 6).³⁹

Table 1. PJM Breakdown of Annual and Seasonal Capacity Performance Resources, 2020-2021 BRA

Resource Type	Offered MW (UCAP)			Cleared MW (UCAP)		
	Annual	Summer	Winter	Annual	Summer	Winter
GEN	170,591.7	184.7	485.9	155,572.4	6.2	397.9
DR	8,367.2	1,479.5	-	7,531.5	288.9	-
EE	1,839.0	403.5	-	1,607.4	102.8	-
Total	180,797.9	2,067.7	485.9	164,711.3	397.9	397.9

Figure 6. Energy Efficiency Savings by Type of Organization in the ISO-NE Capacity Market



II. Bidding Aggregated DR and DER into the MISO Market

This section looks at DER aggregation from the perspective of MISO and provides a brief overview

³⁹ Neme, C., and Cowart, R. (2014). Energy Efficiency Participation in Electricity Capacity Markets – The US Experience. Regulatory Assistance Project. Retrieved from: <http://www.raponline.org/wp-content/uploads/2016/05/rap-nemecowart-ee-participationinelectricitycapacitymarkets-2014-sept-12.pdf>.

of the relevant MISO rules, as well as barriers to growth of DER aggregation at the MISO level. MISO has organized a number of stakeholder processes to review these issues.

MISO rules recognize a range of DERs, including DR (such as controllable load) and BTM generation. The rules allow for various types of DERs to compete for revenue in MISO's markets and compensation mechanisms. More specifically, MISO rules, in principle, allow DERs to earn revenue through:⁴⁰

- Participation in energy markets, which are the main markets where resources compete to sell kWh on a day-ahead and real-time basis.
- Provision of ancillary services. This includes compensation for specific products, as defined by MISO rules: Regulation Reserve, Spinning Reserve, Supplemental Reserve, and Ramp Capability.
- Provision of emergency response services, which allows the DER to access special compensation for availability during emergency episodes. These emergency periods are initiated at the discretion of the system operator – for example, in response to tight conditions on hot summer days. This has been a main area of participation of DERs in MISO to date and MISO plans emphasize the importance of DR for extreme summers (emergency resource).⁴¹
- Participation in the planning resource auction, which is a mechanism intended to provide additional incentives to ensure that adequate resource capacity (generation and other resources) is available to meet planned objectives in future years. DERs are able to compete with generators to earn capacity credits, by committing to be available as capacity in the future.

To date, DER participation in MISO markets has been weak compared to PJM and other leading ISOs/RTOs. According to MISO's 2017-2018 planning resource auction results, DERs accounted for about 9,500 MW of capacity, 7% of the systemwide total.⁴² This represented an increase in DER capacity of only 2% from the previous year. However, MISO and its stakeholders expect an increasing rate of growth for DER participation in coming years.⁴³

Before that rapid growth in DER participation can be realized, MISO may need to address a

⁴⁰ Midcontinent Independent System Operator, Inc. (2017). Demand Response Primer and Training Guide. Retrieved from: <https://cdn.misoenergy.org/Demand%20Response%20Primer118479.pdf>.

⁴¹ MISO (2017). MISO 2017 Summer Readiness Workshop. Retrieved from: <https://old.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2017/20170508%20Summer%20Readiness%20Workshop/20170508%202017Summer%20Readiness%20Workshop%20Presentation.pdf>

⁴² MISO Resource Adequacy Subcommittee (2017) 2017/2018 Planning Resource Auction Results. Midcontinent Independent System Operator, Inc. Retrieved from: <https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf>.

⁴³ One MISO official predicts 20,000 MW of DERs by 2030. Cook, A.D. (2017). Stakeholders Hash Out Future of DER at OMS Workshop. RTO Insider. Retrieved from: <https://www.rtoinsider.com/miso-distributed-energy-resources-der-47171/>.

number of barriers.^{44,45} First, as noted in a previous section, MISO's minimum size threshold for participating DERs is high. The minimum thresholds for a DER to fully participate in energy and ancillary services markets is typically 5 MW, compared to a 100 kW minimum threshold in PJM. Individual resources – and some aggregations – are generally far too small to meet this threshold. DERs of 1 MW or larger can participate in MISO in a more limited fashion, including as load-shedding emergency resources.

Second, MISO rules include fairly strong geographical restrictions, limiting the scope of a given aggregated bundle of resources to a particular nodal zone, which represents another hurdle to aggregators to assemble a viable resource for participation in MISO markets. Having said that, allowing completely unrestricted aggregation across the entire MISO footprint may not be desirable.⁴⁶ For example, aggregating resources on different sides of a major transmission constraint will need to be handled carefully to support efficient system operations. The key will be to find a workable middle ground and design rules to ensure that MISO market structures and operational procedures can unlock the benefits of aggregation across the footprint. This point is related to a third barrier, which is that MISO currently has limited visibility over DERs, from an operational or planning perspective. This is a problem across ISOs/RTOs and will become a greater issue as DERs continue to grow.

Other problems in MISO related to DER aggregation that have been discussed by analysts and stakeholders include:

- Over-emphasis on DR as an emergency resource (which is infrequently invoked by the system operator);
- Rules for storage are still evolving;
- Overly complex rules for DERs (with insufficient training and outreach efforts), which may deter participation; and
- Need for improvement in planning processes to allow for better recognition of the full value of DERs in meeting system reliability goals, and also for recognizing the value of DERs as alternatives to transmission and distribution investments.

The OMS DER work plan efforts can play an important role in helping to resolve these various barriers. Information sharing with stakeholders in other ISO/RTO regions will be very important as progress with various specific issues may be uneven across the country.

⁴⁴ Tweed, K. (2016). Does the Midwest Need Demand Response? Greentech Media. Retrieved from: <https://www.greentechmedia.com/articles/read/does-the-midwest-need-demand-response>; and St. John, J. (May 2017) Startup Voltus Unstealths With 400 Megawatts of Demand Response. Greentech Media. Retrieved from: <https://www.greentechmedia.com/articles/read/startup-voltus-unstealths-with-400mw-of-demand-response>.

⁴⁵ Dahlke, S. (2015). Integrating Clean, Distributed Energy Resources (DER) Into the Electric Grid Requires Updated Market Rules. Great Plains Institute. Retrieved from: <http://www.betterenergy.org/blog/integrating-clean-distributed-energy-resources-der-electric-grid-requires-update-market-rules>.

⁴⁶ For discussion on related issues see "Comments of the Organization of MISO States: Electric Storage Participation in Markets Operated by Regional Transmission Operators and Independent System Operators."

III. Aggregation of DERs by Entergy Arkansas

A. Demand Response Programs

EAI currently offers one tariffed DR program to commercial and industrial customers, an Optional Interruptible Service Rider.⁴⁷ Participants establish by contract with EAI a level of firm demand that is not interruptible. Everything above the firm demand can be curtailed as needed by EAI, with advance notification, and with caps on frequency and duration of customer curtailments.

Participants pay a higher monthly customer charge, but lower demand and energy charges (the details are complicated and depend on which tariff the customer is on). EAI may register the curtailable load of participating customers as LMRs in the MISO wholesale market.

EAI also offers optional DR programs under the umbrella of its broad portfolio of ratepayer-funded demand-side management programs. These include:

- **Summer Advantage** – This program, launched in 2012, uses direct load control of air conditioners to help EAI manage summer peak events. Direct Cycling Units (DCUs) are installed on participating customers' air conditioners that can be activated remotely to decrease peak demand. Participants receive a cash reward at the time the DCU is installed and for each year of participation. EAI partners with Comverge, one of the nation's largest DR aggregators, to implement the program. The program goal was to enroll 35 MW of controllable load. EAI reported that more than 23,000 air conditioners and 28 MW of load were enrolled in the 2016 program year.⁴⁸ EAI offers this aggregated DR resource in the MISO market as an LMR. In the 2016 program year, the costs of this program exceeded the benefits and new enrollments were discontinued.⁴⁹
- **Agricultural Irrigation Load Control** – Eligible participants receive cash incentives in exchange for allowing EAI the right to interrupt their irrigation pump motors during summer peak events. This program is implemented by BPL Global on behalf of EAI. Here too, the aggregated DR resource is bid into the MISO market as an LMR. The previously cited annual report for the 2016 program year indicates that more than 1,500 motors and 17 MW of controllable load were enrolled.

⁴⁷ Entergy also offers optional time-of-use rates that are sometimes considered a passive (uncontrollable) form of DR. Entergy's complete tariff book is online at http://www.apscservices.info/tariffs/1_elec_1.PDF.

⁴⁸ Entergy Arkansas, Inc. (2017). Arkansas Energy Efficiency Program Portfolio Annual Report. Retrieved from: <http://www.apscservices.info/EEInfo/EEReports/Entergy%202016.pdf>.

⁴⁹ The costs per customer of the Summer Advantage program are fixed, but the benefits depend on how often Entergy controls those loads to address emergency conditions or to reduce wholesale costs. MISO currently has a great deal of excess capacity, which not only reduces the frequency of emergency DR events, but also reduces real-time energy and capacity costs in the wholesale market (and thus the costs that can be avoided via the Summer Advantage program). This recent development at a MISO utility is consistent with the results of the previously cited study of DR values for the California PUC, which found that the value of load-shed DR to an ISO or RTO diminishes when there is high renewable generation or significant excess capacity.

- **Bring-Your-Own-Thermostat Pilot** – This is a new three-year pilot program launched in 2017. Participating customers will receive a Wi-Fi connected, smart thermostat (installed, at no cost) and incentive payments if they allow EAI to remotely cycle their air conditioner off or adjust the temperature setting during summer peak events. Previously installed Wi-Fi connected, smart thermostats are also eligible to participate. Participants will receive a \$25 reward at the time of enrollment and \$25 each year they participate. As with the Summer Advantage program, EAI is partnering with Comverge to implement this program. Enrollment data are not yet publicly available, but the targets for the pilot program are 750 participants and 0.9 MW of load.

B. Discussion of AMI Rollout

In September 2016, EAI filed with the Arkansas PSC a plan to deploy AMI, including installation of smart meters across the company's service territory over a three-year period beginning in 2019. Customers would have the option to opt out of receiving a smart meter. In an October 2017 order, following a proposed settlement by the parties to the case, the Arkansas PSC found that EAI's proposal to deploy AMI was in the public interest.

Among the many potential benefits of AMI is that it will enhance the ability of EAI or ARCs to aggregate more DERs – especially those within the residential sector, where smart meters have not been widely deployed to date — for the low-cost provision of essential grid services. To unleash the full potential of DERs to provide grid services, it is necessary for an aggregator to have visibility of the capabilities and operating status of participating DERs, interval data on each participant's energy consumption (or injection), and the ability to send control signals to the customer's premises. This requires a smart meter and two-way electronic communications between the aggregator and its customers. Smart meter data can also assist aggregators with assessing the potential for new program offerings, and assist customers with determining if they could benefit from such programs.

The planned deployment of AMI in EAI's service territory thus offers a new opportunity to expand DER aggregation. For example, the settlement reached by the parties to this case includes a provision that "EE and DR programs enabled by AMI will be submitted for Commission review and approval as part of Entergy Arkansas's EE program portfolio along with all other EE programs." However, the PSC's October 2017 order did not resolve all the issues that must be resolved to unleash the full potential of aggregated DERs. In its order, the Commission noted its intention to keep the docket open and expand it to explore "data access issues and questions that touch on matters that may affect other utilities, customer groups, and third parties that may have an interest in accessing customer data and integrating DER into the grid."

IV. Regulations for Third-Party Aggregators

A. Certification of Aggregators - Scope of Authority

The Commission is required under the statute to make a finding that aggregators operating in the competitive market are in the public interest. With that finding, the ARCs would be required to follow the Commission's regulations which would also apply to ARCs who are selling services to the public and not acting as an agent of the utility under a contract.

As noted above, aggregators are defined in Arkansas law as follows:

“(1) (A) ‘Aggregator of retail customers’ means a person that aggregates demand response from retail customers for the purpose of marketing, selling, or marketing and selling the aggregated demand response:

- (i) To an electric public utility; or
- (ii) Into a wholesale electricity market.

(B) ‘Aggregator of retail customers’ does not include:

- (i) An electric public utility to the extent that it engages in demand response programs or demand response aggregation activities with the retail customers in its own service territory as certificated by the Arkansas Public Service Commission; or
- (ii) A municipally owned electric utility or consolidated municipal utility improvement district to the extent that it engages in demand response programs or demand response aggregation activities with the retail customers in its own service territory;”

The Commission has explicit authority to regulate ARCs:

“(a) The marketing, selling, or marketing and selling of demand response within the State of Arkansas by electric public utilities or aggregators of retail customers to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets is subject to regulation by:

- (1) The Arkansas Public Service Commission under Acts 1935, No. 324, as amended ...

(b) The commission:

- (1) May establish the terms and conditions for the marketing, selling, or marketing and selling of demand response by electric public utilities or aggregators of retail customers to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets; and
- (2) Shall not regulate demand response investments or demand response actions

of a retail customer on the customer's side of the electric meter.”

Thus, in order to protect consumers and ensure that they are dealing with financially solvent and technically competent aggregator companies the Commission should consider establishing a certification process. This should apply for independent aggregators who are not contracting directly with the utility and acting as an agent for the utility. Any aggregator marketing directly to consumers and selling the aggregated services into the wholesale market would need to be certified by the Commission, and would need to follow whatever requirements MISO may have. It is not uncommon for Commissions to regulate competitive energy service providers with respect to terms and conditions of service and analogies can be found with competitive retail suppliers in deregulated states. These regulations typically include a certification process. Moreover, entities are prohibited from engaging in the marketing of DR unless the Commission finds that it is in the public interest.

Attached as Appendix A is a draft certification rule that addresses the timeline and requirements for certification.

1. Scope of Regulation/Commission Legal Authority

Arkansas Code § 23-18-1003 grants the Commission the authority to regulate DR. Specifically, the Commission:

- (1) May establish the terms and conditions for the marketing, selling, or marketing and selling of demand response by electric public utilities or aggregators of retail customers to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets; and

- (2) Shall not regulate demand response investments or demand response actions of a retail customer on the customer's side of the electric meter.

Demand response is defined to mean “a reduction in the consumption of on-peak or off-peak electric energy by a retail customer served by an electric public utility or a municipally owned electric utility or consolidated municipal utility improvement district relative to the retail customer's expected consumption in response to:

- (i) Changes in the price of electric energy to the retail customer over time; or
- (ii) Incentive payments designed to induce lower consumption of electric energy.”

Accordingly, the Commission has the authority to issue incentives to achieve necessary reductions in demand.

As these provisions of the Arkansas statute point out, the Commission has the authority to regulate the terms and conditions of service, but not the prices charged or compensation offered to retail customers. This is because the aggregation services are subject to competition in which market forces are at work to keep prices down. Regulation is a substitute for competition and is not necessary where a fair market environment exists to offer customers choices.

As part of the regulations that the Commission can consider, as noted above, certification of market entrants – in this case aggregators of retail customers – is critical to ensure that only reputable

entities are marketing to customers. This is a key element in customer protection. There are a number of areas in which the Commission may want to consider promulgating regulations. They include but are not limited to:

- Providing minimum standards for service quality;
- Providing consumers with sufficient information to make informed decisions about choosing an aggregator or retail customers;
- Protecting consumers against misleading, deceptive, unfair, and unconscionable acts and practices in the marketing, solicitation, and sale of aggregated DR services and in the administration of any contract for that service;
- Requirements of transparency in transactions;
- Customer consent and enrollment procedures;
- Standardized contracts for all similarly situated customers, (example, residential customers) reviewed by the Commission;
- Requirements in contracts:
 - Company contact information;
 - Clear explanation of rights and responsibilities;
 - Clear explanation of all financial aspects of the transaction including any costs and payments to both parties;
 - All costs to the customer, if any, should be fully disclosed, including any penalties if the customer overrides the demand controls; and,
 - The compensation rate to the customer for allowing its load to be controlled should be clearly set forth.
 - Marketing materials should be consistent with contract terms – no bait and switch;
 - All materials should be accurate, factual, easy to understand;
 - Contracts should disclose estimated amount of energy subject to DR; controls and the duration and number of hours the customer’s usage can be curtailed;
 - Contract term;
 - Privacy provisions for customer information; and,
 - Termination provisions.

Other duties of the Commission may include:

- Approving or disapproving certification applications;
- Establishing rules on customer complaints;
- Adjudicating complaints and investigating practices by a retail aggregator of customers;

- Ability to monitor the demand aggregator business as needed; and
- Impose penalties and corrective actions, including suspension or termination of certifications.

The Commission is excluded from regulating rates as that is within the province of the competitive market. However, given that the DR program is designed so as to pay customers for participation, this issue is more about fair compensation to the customer than rates charged to the customers. At the beginning, there may not be too many market entrants to ensure a robust, competitive market. However, if the compensation is too low for customers, they may not deem it worthwhile to participate, so the aggregators are obligated to find the right level that will induce participation and allow them to earn a return. If customers are being harmed under the contract terms, the Commission does have the power to investigate and the consent to jurisdiction required in the certification process reinforces this.

Appendix A attached to this document sets forth an example of certification rules that the Commission may consider in regulating ARCs.

V. Performance Incentive Metrics to Encourage Third-Party Aggregation

A. Measures – Identification of Commission Policy Objectives

As noted above, Arkansas' state statute has recently articulated a state policy to encourage aggregation of services that include demand response. The execution of this policy falls within the purview of the Arkansas PSC. The Commission has also expressed an interest in enabling the development and offering of other DER services which can serve to increase the reliability of the grid when strategically located, and reduce the need for new capacity. DR in particular can be a key contributor to reducing high-cost peaking capacity. Thus, the Commission is seeking to implement policies that remove barriers to entry for aggregators, encourage customer participation – the key to the success of DR – and also incentivize utility cooperation and support. The goals of the Arkansas Commission revolve around the successful implementation of aggregated DR as set forth in Act 1078 and the expansion toward a modernized grid through the deployment of DERs. Further, as AMI is adopted in the state, the goals could include rate designs that better align cost with causation.

PBR is a method to focus utility attention on regulatory and public interest goals of the jurisdiction. Instead of solely evaluating utilities' expenses and adding a regulated rate of return on capital costs, PBR focuses on the outcomes that stakeholders (legislators, regulators, utilities, consumers, and other advocates) articulate and rewards utilities for their performance on these outcomes. While traditional cost-of-service (COS) regulation looks at performance in terms of sales, revenue,

rates, and often service reliability, safety, and quality, PBR also incentivizes things like customer engagement and empowerment, management practices, environmental goals, and cost-effectiveness.

PBR can take on a variety of forms, from individual mechanisms to wholesale revision of the regulatory paradigm. Individual mechanisms, or performance incentive mechanisms (PIMs), act as an overlay on a traditional COS regulatory framework. PIMs set specific performance metrics to affect utility behavior in a way that furthers the priorities of the jurisdiction. They can provide an increment or decrement of revenues around an authorized rate of return to strengthen performance in target areas.

Below are some PIMs that the Arkansas Commission can use which will advance the Commission's goals of modernizing the grid and focusing on aggregated demand response. By implementing PIMs, the Commission can ensure the utility focuses on energy efficiency, demand response, aggregation and DERs. Focus on these specific areas will collectively either directly encourage aggregation, or other measures that will modernize the grid. Measures that the Commission could take to address these goals include the following:

- EE measures
- DR measures
- Measures to promote aggregation
- Measures to encourage DERS
- Measures to focus DERs in specific locations

B. Metrics

1. EE metrics

Numerous US jurisdictions have used PBR to motivate adoption of EE goals and satisfaction of targets and metrics. For example, as depicted in Figure 7, at least 26 US states have used performance incentives to encourage EE deployments. These incentives range from allowing a utility to earn 1) a percentage of program costs for achieving a savings target (eight states), 2) a share of achieved savings (13 states), 3) a share of the net present value of avoided costs (four states), and 4) an adder to the rate of return for achieving savings targets (one state). Over time, EE program performance improved markedly in states offering these incentives.⁵⁰

The purpose of EE metrics is to provide an indication of customer participation, the amount of energy and demand savings, and the overall cost-effectiveness of each utility's EE programs.

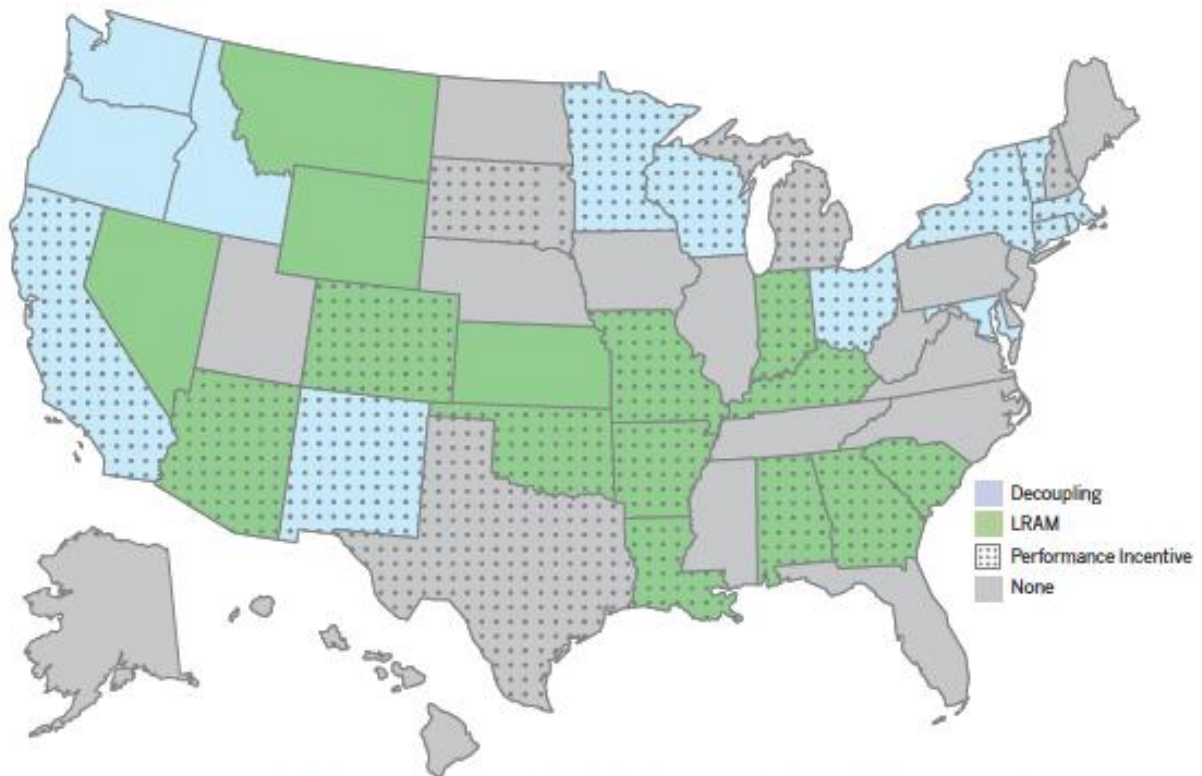
⁵⁰ State and Local Energy Efficiency Action Network (2016). SEE Action Guide for States: Energy Efficiency as a Least Cost Strategy to Reduce Greenhouse Gases and Air Pollution and Meet Energy Needs in the Power Sector. Prepared by: Lisa Schwartz, Greg Leventis, Steven R. Schiller, and Emily Martin Fadrhonc of Lawrence Berkeley National Laboratory, with assistance by John Shenot, Ken Colburn and Chris James of the Regulatory Assistance Project and Johanna Zetterberg and Molly Roy of US Department of Energy. Retrieved from: <https://www4.eere.energy.gov/seeaction/system/files/documents/pathways-guide-states-final0415.pdf>. See pages 12-13 citing numerous sources.

Typical EE metrics include:

- Number and percentage of customers participating per year;
- Number and percentage of unique customers participating since program inception (or over the past x years);
- Annual and lifecycle energy savings (MWh);
- Peak demand savings (MW);
- Net benefits (\$); and
- Program costs per MWh energy saved.⁵¹

Energy efficiency metrics are included with DER aggregation metrics, because an EE portfolio is itself an aggregation of EE resources.

Figure 7. Regulatory Approaches to Promote Efficiency, by State



Thirty-six states have adopted regulatory approaches to promote utility investment in energy efficiency: decoupling, lost-revenue adjust mechanisms ("LRAM"), or performance incentives.

⁵¹ Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Incentive Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%202014-098_0.pdf.

2. DR metrics

The demand side of the power sector has historically been unresponsive to supply-side conditions.⁵² New technology is now enabling customers from all segments to behave more responsively to the real-time price of energy, and enabling them to receive payments for shifting their demand when grid conditions necessitate it. This is occurring through both regulated utility programs and via private third parties; in both scenarios, an entity is responsible for aggregating groups of customers, calling upon them to reduce demand when needed, and facilitating a payment for services. DR programs are growing in number and sophistication, with some aggregation schemes allowing participation in wholesale power markets. There are still many technical and regulatory barriers to entry, with unresolved issues in many markets concerning, *inter alia*: access to customer and market data, the role of third-party aggregators, and the reliability of and fair compensation for DR resources. As increasing amounts of low-cost variable renewable energy drive the need for greater system flexibility, the aggregation of DR may prove to be an even more valuable resource for many power systems.^{53,54}

Regulators can use utility-specific economic and engineering studies to set targets. EE and DR potential studies can identify the amount of investments that would be cost-effective for the utility to make. These studies can help regulators identify and define specific resource investment targets and costs.⁵⁵

Metrics associated with DR depend in part on the goals to be achieved. DR can be used for peak load reduction, load reduction to avoid targeted infrastructure investment, customer engagement, ancillary services to accommodate variations in net load, etc. Metrics for DR typically include:

- Number and percentage of customers enrolled;
- MW of DR available;
- potential and actual peak demand savings;⁵⁶
- Number of customers and MW enrolled by aggregators in direct load; control programs or other DR programs; and,
- Number of DR events called.

⁵² A notable exception to this statement is the example of large industrial customers (e.g., aluminum smelters) who enter into interruptible load demand response contracts with utilities, oftentimes for contingency events.

⁵³ In competitive markets, the energy service company (ESCO) business model is predicated on monetizing a portion of the value associated with saving consumers money on their electricity bills. ESCO revenues are generated by sharing the savings achieved and thus driven by reductions in savings from retail prices. Whether that model can now extend into energy supply and potentially wholesale markets is an open question.

⁵⁴ Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Xuan, W., Zinaman, O., and Logan, J. (2017). Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation. Golden, Colorado: National Renewable Energy Laboratory. Retrieved from: <https://www.nrel.gov/docs/fy17osti/68512.pdf>.

⁵⁵ Whited et al., 2015, p. 37.

⁵⁶ If a policy goal is to improve the system load factor by reducing peak demand, it is not meaningful to simply report the number of customers enrolled in a demand response program, as this provides no information regarding whether these customers actually reduce demand, and by how much, during peak periods. To be useful, a metric should reflect whether the underlying policy goal is being met; e.g., whether peak demand has decreased over the prior year. Whited et al., 2015.

3. Aggregator metrics

Aggregation of DERs is still fairly new, although there is growing experience with aggregation of DR. Metrics that focus on aggregation allow the Commission and stakeholders to monitor the robustness of the competitive market. These numbers are indicators that can help determine whether other actions are necessary to encourage aggregators to compete, or whether barriers to competition need to be tackled more forcefully.

Metrics for aggregation include the following:

- Number of ARCs participating in organized wholesale markets (possibly broken down by energy markets, capacity markets where they exist, ancillary service markets);
- Number of customers/resources/capacity of each type aggregated by ARCs;
- Number of utilities aggregated DERs in the state including capacity, energy value and peak reduction of the DERs; and
- Number of customers/resource/capacity aggregated by utility service territory.

This is a developing area, and more metrics will become evident as experience grows among jurisdictions.

4. DER metrics

PBR can be used to set incentives for greater DER penetration. These incentives are important to overcome the disincentive the utility experiences from DERs otherwise. DER investments potentially reduce the need for utility investments, DERs also reduce utility sales volume, which reduces utility revenue in the short run. The utility desire to build rate base and increase the volume of sales (the “throughput incentive”) gives utilities two strong economic and structural incentives to resist DERs, even in scenarios where they are the lowest cost resource option available. These factors can become barriers to deploying DER solutions.⁵⁷

Depending on the goals of the jurisdiction and the level of penetration of the resources, some of the metrics below can be structured as tracking metrics, which require tracking and disclosure of the information, but do not associate a financial incentive with the data. Tracking metrics allow the Commission and stakeholders to gather information about new resources, which can form the basis for future plans that can make the most effective use of DER grid services.

The metrics for DERs listed below can be for purposes of tracking process or can have an incentive or penalty, depending on the Commission’s inclination. They include the following:

- Number of installations per year (PV, combined heat and power/CHP, small wind, EVs⁵⁸);
- Net metering installed capacity (MW);

⁵⁷ Littell et al., 2017.

⁵⁸ With respect to EVs the Commission can initially require a tracking metric to determine the number of EVs. This could be informational gathering to determine if a special rate is needed for EV charging and whether there are barriers to EV charging stations that should be addressed.

- Net metering MWh sold back to utility;
- Net metering number of customers;
- MW installed by type (PV, CHP, small wind, etc.);
- Number of storage installations per year;
- MW installed by type of storage (thermal, chemical, etc.);
- Percentage of customers with storage technologies enrolled in DR programs;
- Percentage of customers with EVs enrolled in DR programs;⁵⁹ and
- Number of customers by customer class participating in DR programs.

In order to facilitate the development of ARCs, other metrics can be developed:

- Number of ARC providers;
- Number of customers enrolled with ARCs;
- MW of DR sold by ARCs to the utility;
- MW of DR sold by ARCs to MISO; and
- Number of ARC complaints to the utility regarding access to data. (Alternatively, the Commission can put rules in place to require access and monitor utility compliance.)

5. Locational DER metrics

By concentrating DERs in a high-cost utility area (i.e., an area where short-term marginal costs of system improvements are high), DER investments may help to defer or avoid grid upgrades. Infrastructure and operational cost savings can offset utility revenue losses and make net savings available for a PBR shared savings to reward utilities for cost reductions and innovation.⁶⁰ This is perhaps most easily accomplished in vertically integrated utilities where savings from DERs in supply and utility plant accrue to the utility. This model of sharing of location energy data can be structured in a PBR system to designate high-cost utility areas for DER development as high value. The structure of the PBR system would incentivize the utility to provide customers and third-party developers with data on where DERs are most desirable, i.e., have highest system value.⁶¹

This is what New York did with the Brooklyn-Queens Demand Management Project, where the utility provided incentives to direct DER developments to high-cost areas. Incentives included: direct payments to DER providers or customers; direct DER investment by the utility where legally

⁵⁹ Whited et al., 2015.

⁶⁰ Regulatory Assistance Project (2000). Performance-Based Regulation for Distribution Utilities. Retrieved from: <https://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf>.

⁶¹ Littell et al., 2017.

authorized; or facilitated competitive procurements among DER providers with payments to DER vendors capped at the utility savings.⁶² The utility was allowed to recover the costs of DER assets acquired by it and also an additional return on equity (ROE) adder if it was successful in acquiring adequate demand-side reductions through its DER acquisition process. While this can be described as a shared savings system, implementation occurred through an ROE adder and allowed recovery of utility costs for direct utility procurement of DER assets in a particular high-cost area. The measurable performance criteria and metrics were for specific load reductions to be achieved through DER procurements by the utility itself.⁶³

C. Establishment of Baseline

From the regulator's point of view, getting the foundation of PBR set properly is critical. PBR schemes do not start from scratch — they are tied to a foundation. Incentives and penalties are set on top of a baseline. To get the baseline level right, regulators may need to model out and set prices for utilities functioning properly under a COS rate structure. PBR does not avoid the need to properly set base rates and regulatory effort to shape the incentives. First regulators must create a baseline, which may be COS regulation, then design the incentives around the baseline.

EAI has a Formula Rate Plan. In this regard, the baseline could be established based on a determination of utility expenses and rate base items. The return on ratebase could be established using a cost of debt or some other measure. Under this scheme, achievement of each utility performance metric would be assigned a value and would be added to the return with the opportunity for the utility to receive a maximum return, which may or may not exceed the authorized level of return the utility would have received under traditional COS regulation. Where formula rates are in use, the rates would need to be reviewed annually and adjusted based on the utility's performance.

A less dramatic way to ease into performance-based formula rates is to set a band above and below the authorized return and allow for adjustments to the authorized rate of return within that band. A sharing mechanism could be used to split revenue variations that are outside the band. The goal here is to motivate utility behavior with both incentives and penalties. Regulators would need to determine the allocation of shared savings and penalties that fall outside the band. This determination should include how much of the savings for exceeding the band the utility should keep and how much of the revenue reduction (through a lowered rate of return) it should expect for falling below the band.

One difficult issue regulators will need to address in structuring PBR mechanisms focused on DER is setting an appropriate baseline of expected business-as-usual (i.e., no utility intervention) DER deployment. DER markets and technologies are rapidly evolving, and investment decisions are made by consumers for a variety of reasons that can be difficult to project or model. Notably, many DER deployment drivers are outside the direct control or influence of utilities. This makes it difficult to set a PBR mechanism to determine what DER deployment should be attributed to the utility, and

⁶² Whited et al., 2015.

⁶³ Littell et al., 2017.

what would have happened without any utility involvement. As a result, directly attributing specific utility activities to DER deployment (i.e., measuring a utility's value-added) may be a challenge. A baseline must be developed before a PBR mechanism can be created, and it is difficult to start with an *ex-ante* baseline, because DER technologies markets are emerging. The inability to develop a baseline or predict DER deployment trends poses a challenge in developing directional incentives as well as measurable performance criteria and PBR metrics. If a baseline is developed, any DER deployment in excess of this baseline could in theory be attributed to the utility, for the purposes of PBR.

The Commission could consider convening a workshop or soliciting comments from DER stakeholders to identify their needs and barriers to the development of DERs. This would provide the Commission with tangible actions a utility could take to alleviate any of the barriers that have prevented robust deployment of DERs. Moreover, like New York's Reforming the Energy Vision (REV) process, the Commission can require the utilities to identify circuits or areas that would benefit from DER deployment as a lesser-cost alternative to infrastructure upgrades and reward the utility for facilitating opportunities through competitive bidding or other mechanism that result in DER upgrades.

D. Considerations in Developing Targets

Once the Commission has identified areas where utility actions (such as better access to data, etc.) have been developed, the Commission can then develop a series of milestones toward progress. Those milestones can be used to establish targets. Examples might be actions taken by the utility to provide better access to customer data, putting in place a process to identify where DERs can benefit the system and facilitating the interface between the customer, the DER provider and the utility to make customer transactions as seamless as possible. Other activities a utility can undertake include ensuring that interconnection procedures are efficient, not overly burdensome and accomplished in a timely manner. This is particularly important to DG customers. The speed at which a utility installs AMI meters and optimizes their use for end-use customers will also be an important aspect. Another potential target or measure is the utility's activities in advertising and marketing to increase customer awareness as to their options.

E. Incentives and/or Penalties

Arkansas law speaks only to incentives, not penalties.⁶⁴ Therefore, Commission activities should be focused on incentives only. This is also the case in New York, where the PSC provides incentives for good behavior, but no penalties. For its first foray into incentives, the New York PSC has allowed for a 100-basis point adder to the rate of return, which is divided among multiple activities. An important consideration for the Arkansas Commission, should it decide to provide an adder to the rate of return, is to calculate the monetary value of an adder and to compare it to the value of the activity sought from the utility. The value of the utility activity should always exceed the value of the adder being provided to the utility in a cost-benefit analysis. Starting with modest incentive

⁶⁴ AR Code, Section 23-18-1003.

payments can help ensure a proper cost-benefit ratio; however, it is also important to consider what level of incentive will motivate utility action, especially since there is no penalty for utility failure to achieve a target. With a shared savings approach, the savings are the benefit which should exceed the costs and the utility gets to keep a percentage of the savings. This may be a safer way to guarantee customer benefits. These options are discussed in more detail below.

F. Potential Structures for the Performance Incentives

In considering the appropriate structures for performance incentives, consideration should be given to outcome-based incentives. These are metrics that encourage utilities to motivate third-party activity that increases system efficiency and can result in least-cost options. Outcome-based incentives encourage utilities to make the most efficient decisions for their systems and allow regulators to focus more on technology changes and state policy goals.⁶⁵

Performance incentives that may be of use in Arkansas include the following:

1. Shared Net Benefits

Under shared net benefit incentives, the utility would share along with ratepayers in the benefits associated with, and identified from, the metric achieved. This can mean sharing in financial benefits between the utility and ratepayers. In the context of EE programs, a “shared savings” approach is often used in the United States to recognize and share the energy efficiency savings between ratepayers and the utility. Arkansas uses a shared benefit approach with its EE programs.

A shared net benefits approach needs to be carefully thought out and implemented to clearly identify the shared benefits, ensure the utility appropriately controls costs, and ensure the mechanism will not be gamed. Implementation of shared savings schemes use evaluation, measurement and verification (EM&V), to determine as accurately as possible – but not with perfect provision – the shared net benefits. This approach relies on accurate benefit calculations through EM&V that can be used to determine an appropriate level of incentives based on the savings to the utility – and concomitantly, its customers for meeting clearly established metrics. For example, with energy efficiency, if the target reduction in load occurs that saves customers money, the utility will receive a percentage of those savings as authorized by the Commission.

Shared net benefit mechanisms can blunt the incentive for utilities to control costs, depending on factors such as whether the utility just passes through costs, or receives a mark-up, or is paid for savings delivery regardless of costs. Depending on the structure of the program, implementing PBR constructs can serve to deter these kinds of results. To ensure that cost control incentives are maintained in a PBR scheme with a shared net benefit construct, the mechanism can be designed to apply only to benefits outside a band where earnings are not affected, i.e., a deadband approach. A deadband approach adopts a range around a performance level that results in no

⁶⁵ Littell et al., 2017.

modification or incentive until the range is exceeded.⁶⁶

2. Program Cost Adders and Target Bonuses

Program cost adders provide a payment to the utility for costs of a particular program. Target bonuses provide a payment for meeting a specified performance metric. Program cost adders can be used when a program has a direct utility cost. The program target bonus can be a simple percentage paid to the utility based on program cost. This type of program cost bonus is often a share of a specific program and administrative costs are tied to achieving a target or goal. Of significance, it is tied to expenditures and not savings. For this reason, there may be a disincentive for the utility to control program costs.

Target bonuses are, simply put, a one-time financial incentive for achieving a specific performance criteria or metric. This approach has been criticized for being discontinuous (meaning that minus one unit of performance results in no incentive whereas if the next unit is met, the utility receives the full incentive payment). When regulators want to drive performance to an absolute target, this bonus approach is simple and works. A variation on this approach is to set an incentive to a minimum target. If the utility surpasses that target, the utility can receive a higher incentive payment based on the incremental amount by which the utility exceeded the minimum target.

3. Base Return on Equity + Performance Incentive Payments to Reach Maximum ROE Cap

Under a base ROE PBR, the utility earns a base ROE, and then that return increases based on a performance incentive structure that rewards performance with modifications to the ROE. The utility can increase its ROE through performance incentive adders up to a maximum PBR payment or set of payments. The regulator assigns a value range for a series of metrics, for which the utility would receive a return if it satisfies the metrics assigned. The incentives can also scale higher or lower if certain values are achieved within the specified range. The adder value may vary from metric to metric based on the value assigned by the regulator. A more complex option is to provide a range that provides a level of incentives for satisfying the target and a higher incentive for exceeding it. In establishing this type of PBR mechanism, a regulator may examine the following:

- At what level should the base ROE be set in the event the utility meets none of the targets? Should this amount be its approved ROE from its last rate case or some amount lower or higher?
- What level of maximum allowable ROE incentivizes good behavior without causing the utility to over-earn at the expense of ratepayers?
- What metrics should be subject to an incentive adder?
- For the metrics chosen, what value range should be assigned to each?

⁶⁶ For example, no sharing of savings from energy efficiency may be appropriate within a band of, for example, energy efficiency savings of 0 to 0.02, which are expected to be produced through market forces such as enhanced appliance efficiency standards. So designed, a sharing mechanism with a "deadband" operates as a reward for only exemplary performance for marked increases (or decreases) in performance. For more information on shared net benefit mechanisms and deadbands, see Regulatory Assistance Project (2000), p. 4.

- How much reward should be given for each metric so that the sum-total of all the metrics equals the maximum cap with the base ROE?

For example, the New York PSC in the REV process has allocated 100 basis points of return broadly across all earnings adjustment mechanisms (EAMs). Each utility then has EAMs set in the context of a rate case in which those basis points will be allocated among those mechanisms.

This type of mechanism is typically structured to increase or decrease depending on utility performance. For example, if performance is bad, the return on ROE could decrease. However, Arkansas statute only allows incentives for DR, and so this structure would need to be modified to allow only incentives. As a result, the impact of this type of mechanism would need to be considered carefully. As noted above, the incentive-only approach is being used in New York.

4. Bonus ROE for Capital for Projects or Programs

A bonus ROE for capital invested in a particular project or program provides additional ROE for capital rather than program costs. This is more consistent with traditional rate base principles of allowed ROE only for capital investments in utility plant but tends to favor heavy capital investments. This approach has been used for EE, and certainly could be used for other types of projects. When used, it tends to encourage capital-intensive efficiency investments and has been disfavored for that reason. An additional downside is this mechanism rewards capital spending (an input) rather than efficiency outcomes. To avoid a pure spending/input flaw, a bonus ROE for capital could be awarded only if triggered by exceptional output performance associated with an efficient and least-cost outcome, such as completing the project ahead of cost and under budget.

5. Base Incentives on kWh Reduction Targets

A base incentive for meeting kWh reduction targets would enhance ROE for meeting reduced load target metrics. A reduced load in absolute terms or a reduced load growth could be a PBR directional incentive. Reduced load can occur through deployment of varied distributed resources, including EE and DG. If properly designed, this form of PBR could recognize and reward utilities for investments and system modifications that reward energy efficiency and distributed resources. If improperly designed, it could provide a payment for reductions that new technologies and consumer investments will produce anyway. Furthermore, this directional incentive alone may still also allow for over-investment in utility plants if not joined with other PBR mechanisms to address the Averch-Johnson effect.⁶⁷ For example, even if load growth is reduced to zero, utilities still may pursue projects to continue to invest in rate base to increase earnings, even though those projects have minimal value.

6. Peak Reduction Targets

On a system in which growth in peak demand is driving generation, transmission, or distribution investments, there are potentially systemwide savings available from efforts to reduce system peaks. This can be true on a systemwide basis, and also may be true for individual grid zones or even distribution circuits. Where investments that reduce peak demand can defer or avoid

⁶⁷ The Averch-Johnson effect is identified by economists as the tendency of regulated companies to engage in excess capital investments to increase their profits.

altogether the need for new and more expensive investments, overall system costs can be reduced. PBR mechanisms can be designed to incentivize utilities to pursue these types of cost-saving investments. A PBR mechanism can also reward a utility for creating an environment conducive to the development of ARCs who can provide demand response services to retail customers.

The state of Arizona is considering a different version of a peak reduction strategy to encourage development of clean resources through a “clean peak demand standard” implemented through a Renewable Portfolio Standard mechanism.⁶⁸ This proposal would both increase the renewable energy (renewable portfolio) requirement and add a requirement that new resources be available to meet the net system peak. The net system peak is the time when electricity demand, less wind and solar generation, is highest, and it is increasingly moving later in the day when the sun sets due to increased solar generation on the system.⁶⁹

VI. Functional Separation and Codes of Conduct for Entergy

A. Rationale Behind Functional Separation and Creation of Codes of Conduct

Twentieth-century rules of separation between regulated and unregulated utility businesses are even more critical as new opportunities for competition from third parties and unregulated utility businesses are now present through advanced technologies. Codes of conduct are traditionally used as a way to regulate a monopoly utility’s ability to favor its own affiliates.⁷⁰

Codes of conduct govern how utilities (and their affiliates) interact with unregulated companies that compete with them. Historically, monopolies did not have competition. In the late 20th and now 21st century, competitive opportunities can emerge through restructuring of the electric industry⁷¹ and through advanced technologies offered by energy services companies.⁷² Even in restructured

⁶⁸ Trabish, H. (2016). Arizona Proposal Seeks to Mandate Renewable Generation During Peak Demand Hours. Utility Dive. Retrieved from: <http://www.utilitydive.com/news/updated-arizona-proposal-seeks-to-mandate-renewable-generation-during-peak/432031/>.

⁶⁹ Huber, L., and Burgess, E. (2016). Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future. Berkeley, California: Strategen Consulting. Retrieved from: <https://static1.squarespace.com/static/571a88e12fe131211f1f6e6/t/58405ac4d2b85768c5e47686/1480612551649/Evolving+the+RPS+Whitepaper.pdf>.

⁷⁰ Littell et al., 2017.

⁷¹ Seventeen states and the District of Columbia have adopted electric retail choice. US Energy Information Administration. (2012). State Electric Retail Choice Programs are Popular With Commercial and Industrial Customers. Retrieved from: <http://www.eia.gov/todayinenergy/detail.cfm?id=6250>.

⁷² See for example, the Reforming the Energy Vision proceedings, New York Department of Public Service, Case No. 14-M-0101, February 26, 2015; Public Service Commission of the District of Columbia, Case No.1130, In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability; and California Public Utilities Commission, Distribution Resources Plan: <http://www.cpuc.ca.gov/PUC/energy/drp/>.

markets, utilities maintain monopoly positions over certain services and will often have superior economic resources and access to customer and market information and system knowledge that competing companies cannot match unless it is shared by the utilities. If a utility can use its economic and information advantages, there is the risk it can drive out competitors and operate as a deregulated monopoly, exercising market power. While the rules to prevent anti-competitive behavior can be detailed and in certain respects quite distinct among jurisdictions, there are basic principles that govern the establishment of rules:

- Discrimination in providing access to essential services should be prohibited;
- There should be no sharing of competitive information among companies affiliated with the utility; and
- Cross-subsidization by the utility to benefit a competitive enterprise, such as an affiliate, should be prohibited and carefully monitored.⁷³

By way of recent historical example, many US states enacted codes of conduct as part of their restructuring procedures.⁷⁴ Examples of codes of conduct include the New York PSC's order as part of the REV proceedings,⁷⁵ PEPCO Holdings,⁷⁶ and Dominion Resources Inc. as between its affiliates in North Carolina and Virginia.⁷⁷ Texas and Ohio also have a comprehensive code of conduct addressing the affiliate relationship.⁷⁸ All of these codes of conduct are fairly similar in substance and put into practice the three basic principles described above. These concepts can be applied to multiple aspects of a utility business in which a regulated utility or its affiliate enters the market to offer a competitive service.⁷⁹

Done well, codes of conduct and the associated rules and market monitoring will ensure that power sector transformation results in a robust DER market with effective competition and transparent transactions in which customers can understand clearly what they are getting in exchange for the price they pay. Competition will drive efficiency and lower prices, benefiting all consumers.

⁷³ Migden-Ostrander, J. (2015). Power Sector Reform: Codes of Conduct for the Future. *The Electricity Journal*, 28(6), p. 4. Retrieved from: https://www.researchgate.net/publication/285216738_Power_Sector_Reform_Codes_of_Conduct_for_the_Future.

⁷⁴ An example of a code of conduct filed in Ohio by the Customer Coalition for Choice in Electricity (1999, October 13). In the Matter of the Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan, Pursuant to Chapter 4928, Ohio Revised Code. Case No. 99-1141-EL-ORD. Appendix C. Retrieved from: http://dis.puc.state.oh.us/TiffToPDF/J_YLZ8DECRL5YXDH.pdf.

⁷⁵ State of New York Public Service Commission, Case Nos. 15-M-0501 and 14-M-0101, Order on September 15, 2016. Retrieved from: https://www.energymarketers.com/Documents/utility_code_of_conduct_DER_order.pdf.

⁷⁶ Pepco Holdings (undated). Codes of Conduct. Retrieved from: <http://www.pepcoholdings.com/codes-of-conduct/>.

⁷⁷ Dominion Energy (undated). Code of Conduct Governing the Relationships between Dominion North Carolina Power, its Affiliates and the Nonpublic Utility Operations of Virginia Electric and Power Company. Retrieved from: <file:///Users/camille/Downloads/codes-of-conduct.pdf>.

⁷⁸ TX Administrative Code, Title 16, Section 25.272. Code of Conduct for Electric Utilities and Their Affiliates. Retrieved from: <https://www.puc.texas.gov/agency/ruleslaws/subrules/electric/25.272/25.272.pdf>.

⁷⁹ Littell et al., 2017.

B. Functional Separation

1. Discussion of options

When creating a new competitive arena in which a regulated utility participates, separation between the regulated entity and its competitive arm is critical. This can be accomplished in three ways:⁸⁰

- **Divestiture** – Requires the disposition or sale of an asset by a company. A company will often divest an asset which is not performing well, if there is low growth holding down other potential investments, if the business is not vital to the company's core business, or because the business is worth more to a potential buyer or as a separate entity than as part of the company.⁸¹ Other reasons for divestiture can include a requirement for an electric utility to spin off a competitive business enterprise in order to ensure that the competitive business has no competitive advantage by virtue of its association with the utility. It removes all financial incentive for any kind of favoritism or sharing of costs or information.
- **Corporate Separation** – Requires the electric utility to separate its competitive enterprise from its regulated enterprise by creating a separate affiliated company. The electric utility and the new affiliate both are part of the same parent or holding company.
- **Functional Separation** – Maintains the competitive arm within the utility as a separate division with its own accounting system, staff, and services. It relies on a “Chinese wall” to eliminate the flow of commercial information between the two divisions.⁸²

2. Rationale for choosing functional separation

Most restructured utilities corporately separated, although some have divested or functionally separated (for example, in New Jersey, two electric companies divested nearly all of their generation while another divested most but not all).⁸³ Utility companies often reject full divestiture because it eliminates a potential revenue stream for the parent company. Alternatively, functional divestiture may not provide the appropriate level of separation between the utility and the affiliate, making the job of monitoring compliance more difficult. An example of this difficulty is how would you monitor a conversation at the water cooler? To avoid this, physical and operational separation are preferred. The division or affiliate should be located in a separate building with separate employees and operations.

Notwithstanding the foregoing, some jurisdictions have chosen functional separation. One example

⁸⁰ Migden-Ostrander, 2015.

⁸¹ Dranikoff, L., Koller, T., and Schneider, A. (2002) Divestiture: Strategy's Missing Link. Harvard Business Review. Retrieved from <https://hbr.org/2002/05/divestiture-strategys-missing-link>; and InvestorWords (undated). Divestiture. Retrieved from <http://www.investorwords.com/1508/divestiture.html>.

⁸² Curien, N. (2007) Functional Separation: Pros and Cons. La Lettre de l'Autorite, No. 55, March/April, pp. 1-5. Retrieved from http://www.arcep.fr/uploads/tx_gspublication/lettre55-eng.pdf.

⁸³ Federal Trade Commission (2001). Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform, p. A80. Retrieved from: <https://books.google.com/books?isbn=142895225X>.

is New York's REV process where the utilities have been required to set up separate divisions with a code of conduct.

3. Ring-fencing

Ring-fencing occurs when a regulated public utility business financially separates from a parent company that is engaged in non-regulated businesses. The purpose of ring-fencing is primarily to protect the utility and its customers from the risks associated with unregulated enterprises and to protect the delivery of essential utility services in the event of financial instability or bankruptcy of the unregulated affiliate.⁸⁴ It insulates the credit risk of issuers of debt to the utility. Another benefit is that ring-fencing can keep the customer information that is in the possession of the utility separate from the unregulated companies.⁸⁵

Ring-fencing is also beneficial to the parent company because it provides more assurance to bondholders that their investments are safe. This also allows the parent company more flexibility to grow its unregulated businesses if it is not constrained with concerns regarding the financial impact on its regulated businesses that are providing essential services.

An example of ring-fencing occurred in December 2001 when Enron collapsed. When Enron acquired Portland General Electric, an Oregon-based utility, the state of Oregon required that ring-fencing be in place prior to the completion of the acquisition. This protected Portland General Electric's assets and thereby, its consumers when Enron declared bankruptcy.⁸⁶

There are several actions a state can take to protect customers from the risks of financial insecurity or debt from the nonaffiliated company. Where these can be legislatively mandated, it provides more certainty to the rating agencies. However, commissions can insist on corporate separation with separate books and accounts. The National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Accounting and Finance made the following recommendations as ring-fencing measures:⁸⁷

1. Commission authority to restrict and mandate the use and terms of sale of utility assets, including restriction against using utility assets as collateral, etc., for any non-utility business.
2. Commission authority to restrict dividend payments to a parent company to maintain financial viability of the utility, including maintenance of a minimum equity ratio balance.
3. Commission authority to authorize loans, loan guarantees, engagement in money pools, and large supply contracts between the utility and affiliate companies.

⁸⁴ Devlin, T., Phillips, R., Ferris, T., et al. (2013). Ring Fencing Mechanisms for Insulating a Utility in a Holding Company System. NARUC Subcommittee on Accounting and Finance. Retrieved from: http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Devlin_Ring_Fencing_Mechanisms.pdf.

⁸⁵ Peterson, C., and Brereton, E. (2005). Report on Ring-Fencing. Division of Public Utilities, Utah State Department of Commerce. Retrieved from: <https://pscdocs.utah.gov/gas/16docs/1605701/286939ExDPetersonTestApp1RepRingFencSept20057-7-2016.pdf>.

⁸⁶ Devlin et al., 2013.

⁸⁷ Devlin et al., 2013.

4. Commission authority over the establishment of a holding company structure involving a regulated utility.
5. Expand commission authority over security applications to include the ability to restrict type and use of financing.

These restrictions will prevent the affiliate from having an unfair competitive advantage through garnering assistance in financing some of its operations through the utility to the detriment of the utility's captive customers.

C. Codes of Conduct

1. Entergy Obligations

a. Non-discrimination

The utility should be prohibited from providing a competitive advantage to its affiliated energy service provider (the affiliate) through any kind of preferential treatment that would extend to any service or price unless the same offer or advantage is contemporaneously provided to all unaffiliated energy service providers (UESPs). This includes the provision or procurement of any goods, services, facilities, information, or the establishment of standards. The timing of any special pricing (such as a discount, rebate, or fee waiver), service, or condition should be the same and simultaneously offered to all. Giving one entity a head start in marketing hinders having a level playing field.

Tie-ins are another area of concern. The utility might require as a condition of any service or special rate, that the customer must procure competitive energy services from its affiliate. An example is if a utility conditioned the purchase of its customer's renewable energy credits on a requirement that the rooftop PV be installed by its affiliate.

In the event of a default of a UESP, the utility cannot assign the contract to its affiliate. A process should be in place to address that situation. For example, if a customer signs a contract with a competitive energy service provider (CESP) for curtailment services and that CESP defaults, there should be a process to provide the customer with an alternate provider who will honor the contract in place. Often the defaulting energy service provider will attempt to sell its book of business to a competitor in order to defray its debt.

More subtle ways that discrimination can occur include: the utility processing requests of the affiliate before the UESP, resulting in faster, better service for the affiliate, which in turn impacts end-use customer satisfaction with the services provided; the utility providing interested customers with information about affiliate offerings only; sharing any kind of market analysis or other proprietary reports not made available to other competitive service providers or the general public; and, giving the appearance that the utility speaks on behalf of the affiliate and vice-versa.

b. Information Sharing and Disclosures

Information on customers should be provided on a non-discriminatory basis to both the affiliate and UESP but only with a customer's written consent. For CESPs needing customer usage history and

past bills, a sample permission form prepared by the utility and approved by the Commission for all to use may be a simple way to address informed customer consent. Rules should be clear that the utility cannot share with the affiliate any information it receives from a UESP. If a utility is to provide customers with a list of CESP, that list should be approved by the Commission and developed so as to not provide any preference or emphasis on the services of the affiliate. Nor should the utility provide customers with any information or advice pertaining to the selection of a CESP beyond the list of qualified service providers arranged in a random, rotating order.

c. Corporate Identification and Logo

The affiliate should have its own separate identification and not use or trade upon, promote, or advertise its business using the utility's name or logo. If such practice is permitted, then the affiliate must disclose legibly or in audible language that the affiliate is not the same company as the utility, is not regulated by the Commission, and that the customer need not purchase the services of the affiliate in order to remain a customer of the utility. Also prohibited should be any kind of joint advertising between the two entities. This is important not only to create fairness in the market (a company with a utility logo or name has recognition that gives it a competitive advantage), but also to avoid customer confusion. Customers have the right to understand who the entity is with whom they are contracting. When the same or similar name and logo is used by the affiliate, it is difficult for the customer to understand that they are dealing with a separate company.

Nor should a utility be permitted to represent that as a result of the affiliated relationship, customers of that affiliate will receive preferential treatment. The separation between the utility and affiliate must be complete and this extends to any kind of joint advertising, sales calls, or call centers, or responses to requests for proposals. If the utility is at a meeting with the affiliate and a potential customer regarding any kind of operational/technical issue, the utility must make itself available to all CESP under equal arrangements. The utility should not share or subsidize any of the costs associated with research and development activities or investments that are designed to benefit or be used by the affiliate.

d. Record keeping

Utilities and their affiliates should each be required to maintain separate books and records in accordance with the applicable Uniform System of Accounts and the Generally Accepted Accounting Principles. The utility should be required to document all tariffed and non-tariffed transactions with the affiliate which includes at a minimum: all discounts, waivers of tariffs, or contract provisions; the names of parties involved in transactions; a description of the transaction; the terms and conditions of the transaction; and the time period involved. These records should be maintained for a term determined by the Commission. They should also be available for review to any requesting party. Without this record keeping, it will be difficult to verify that the codes of conduct are being followed and that true separation between the utility and its affiliate is being adhered to.

e. Transfer of goods and services

In all proceedings, complaints, investigations, and filings, the utility should have the burden of demonstrating the fair market price and that there is no cross-subsidy. Transfers of goods and

services from the utility to the affiliate should be set at the higher of fully allocated cost or fair market price to protect the captive customer from subsidizing the affiliate operation. Alternately, any transfer from the affiliate to the utility should be at the market price to prevent the affiliate from selling any asset or service at an inflated price at the expense of those same captive customers. Any assets, goods, or services that are developed for sale on the open market by the utility should be available to the affiliate and UESP on an equal and non-discriminatory basis. The transference of goods and services also extends to risk from the competitive business not being borne by the utility, for example in guaranteeing performance.

f. Sharing of Facilities, Equipment and Costs

A utility should not share any office space, equipment, services, and systems with the affiliate. The only exception is the manner of the separation between the utility and the affiliate and if corporate support functions are shared. Divestiture is the only form of separation that truly separates the utility from the CESP arm because the non-regulated entity is sold to a non-affiliated company. Integral to the separation of the two entities is the importance of maintaining separate computer systems so that the utility and affiliate do not have access to either's information system.

g. Joint Purchases

A utility should not be allowed to make joint purchases with the affiliate that are associated with the marketing of the affiliate's products and services. If this is permitted, however, the utility must ensure that all joint purchases are priced, conducted, and reported as part of the record keeping so as to clearly delineate the utility's and affiliates portion of the costs.

h. Corporate Support

Corporate support for the affiliate, which consists of overall corporate oversight, governance, support systems, and personnel, can be created through a separate entity or provided by the parent company which also houses the utility. Any shared corporate support should be priced to prevent subsidies and should be recorded and made available for review. The use of combined corporate support should exclude the opportunity to transfer confidential information, provide preferential treatment or an unfair competitive advantage, or lead to customer confusion.

i. Employees

Generally, the utility and the affiliate should not jointly employ the same people. The only exception is the case of shared directors and officers stemming from the corporate parent or holding company. In that case, rules and procedures need to be in place to ensure there is no circumvention of the codes of conduct. As a practical matter, this is hard to do given that the same officers are responsible for the success of both the utility and the affiliate. Other mechanisms include keeping records of any transfer of employees from one entity to the other. Once an employee is transferred, s/he should be required to stay with that entity for a minimum period. Temporary or intermittent assignments or rotations should not be permitted as a means of circumventing these rules. Transfers between the utility and the affiliate allow for too much information sharing and potential violations of the codes of conduct. Employees should be required to sign a non-disclosure statement and acknowledge that they understand the requirements under

the codes of conduct so that there are no misunderstandings regarding permitted and prohibited actions.

2. Commission Regulatory Oversight

Regulatory oversight and the exercise of jurisdiction over the codes of conduct and the competitive market are critical to success. Note, there is a distinct difference between price regulation and the regulation of conduct. Many deregulated businesses (such as the airline industry) have free rein in establishing prices based on what the market will bear but are still regulated as to the terms and conditions of service.

The state commissions recognized the importance of asserting jurisdiction over competition in a deregulated environment when NARUC passed a resolution in July 1998 urging Congress not to pre-empt state jurisdiction over market power.⁸⁸ With this comes oversight of the competitive market which should include compliance plans, compliance audits, complaint procedures and logs, and penalties.

a. Compliance Plan

The utility should be required to file a compliance plan detailing how it will implement the code of conduct and keep all aspects of its operation separate from the affiliate. A plan should also be filed for the affiliate detailing the affiliate's plans to keep its operations separate.

The plan should include an educational component for all employees that covers training and a handbook so that employees of both utilities and affiliates understand what conduct is and is not permissible. Upon completion of the training, requiring employees to sign a document acknowledging that they understand the codes of conduct will help deter them from violations. Having such training in place should not exempt the utility from responsibility for employees' actions.

b. Compliance Audit

The utility should be subject to annual compliance audits prepared by an independent auditor, filed with the Commission, and made available to the public. Audits are a useful tool to identify practices and procedures that are or may lead to violations of the code of conduct.

c. Complaint Procedure and Log

To allow an informal resolution of complaints regarding the code of conduct, the utility should establish a complaint process that calls for a resolution within a defined number of days to record and investigate the complaint and provide a written response to the complainant regarding the utility's findings and any corrective action being taken. If the matter is not resolved to the complainant's satisfaction, the complainant retains the right to file a complaint at the Commission. If the Commission finds probable cause for the complaint, the Commission could set the matter for hearing. The purpose is to give parties an informal opportunity to resolve matters without burdening

⁸⁸ National Association of Regulatory Utility Commission (NARUC). (1998, July). Resolution Relating to Market Power In A Restructured Electric Power Industry. Sponsored by the Committees on Electricity, Energy Resources, Finance and Technology and Gas. Retrieved from <http://www.naruc.org/Resolutions/Resolution%20Relating%20to%20Market%20Power.pdf>

the Commission with every complaint. Each complaint would be kept in a log book that would be available to the public and included as part of the utility's compliance audit.

d. Penalties

While the aspiration is to not have to ever penalize a utility, granting the Commission the authority to do so creates a deterrent effect. The Commission should have flexibility with regard to penalties, which can include: terminating a transaction; limiting the value of the transaction prospectively; or, assessing a penalty that reflects the actual or potential injury to ratepayers and competitors and the gravity and circumstances of the violation. Penalties assessed by the Commission should not preclude a party's right to seek damages. Depending on the breadth and frequency of violations, the Commission can restrict transactions between the utility and the affiliate and/or require customer notification of the violation and how to report complaints.

VII. Conclusions

The deployment of DERs in Arkansas and across the MISO footprint is steadily growing, with every indication that huge potential for additional cost-effective deployment remains. However, under current rules and regulations in MISO, only a fraction of the DER value in the wholesale market is being captured. The state of Arkansas has a statutory framework and the Commission has the authority to set forth the regulations to implement at least DR through aggregation in order to obtain distribution level values. The systemic barriers confronting DER's slows deployment, reduces benefits for participating customers, and results in higher-than-necessary costs for utilities and their customers (DER participants and non-participants alike).

Some of the key barriers to capturing the full value of DERs at the wholesale market and distribution level have been noted in this paper. Below are some of the issues identified in this paper that would need to be addressed at the MISO, SPP and/or state level.

- Underlying economics – there is currently too much emphasis on the peak-shaving/load-shedding capacity value of DR, to the exclusion of other values;
- The short-term capacity value of DERs is currently very low due to excess capacity in MISO;
- SPP does not have a capacity market, thus creating a barrier to the sale of aggregated DER into that market;
- Restrictions on aggregation – current Arkansas statutes allow for aggregation of DERs, but only allows the sale of the DER within the state unless and until the PSC finds that to be in the public interest (which has not yet taken place);
- Utility business model – the well-known utility throughput incentive and the Averch-Johnson effect (rate-base investment bias) discourage customer and third-party investments in

DERs unless mandated, and encourage utilities to resist direct participation by ARCs in MISO;

- MISO rules – the current rules are too complicated. The transaction costs too high for participation by small customers; high minimum bids restrict participation; there is no transparency on the value of DERs in wholesale markets; and the participation rules are unclear for DERs other than DR.

Some of these barriers can be mitigated or removed by the Arkansas PSC, at least as they pertain to utilities and customers in Arkansas. This would require a concerted effort, and possibly a willingness to take a leadership role among the MISO states. But the alternative is to accept the fact that DERs are undervalued and customers are paying too much for electric power.

Actions the Arkansas PSC could consider taking include:

- Continuing the work commenced in Docket No. 16-028-U through its November 9, 2017, order in which it has ordered intervenors to work in a collaborative process led by the staff to comment on a host of DER issues, including: third-party aggregation of DER; AMI data and functionalities; costs and benefits of AMI, the location of system constraints that can benefit from DERs, privacy and marketing; investments in software and systems that might be necessary; customer use of the Green button program; competitive issues; and addressing equity issues and cost allocation as it applies to customers.
- Opening one or more proceedings to answer these questions:
 - Should utilities be encouraged to purchase DR from ARCs in a manner that benefits all stakeholders, through savings for customer participants, system benefits that outweigh costs, and potentially an incentive payment to the utility?
 - Would direct ARC participation in MISO be in the public interest?
 - Could Arkansas utilities cost-effectively reduce their wholesale market costs or defer distribution system investments by procuring more in-state DERs from customers or aggregators?
 - Should elements of performance-based rate-making be adopted for DER goals, in addition to those currently in place for EE programs, to mitigate the Averch-Johnson effect and throughput incentive?
- Ordering utilities to obtain more services from DERs directly or from competitive bidding processes that allow DER aggregators to fairly compete;
- Advocating through OMS for MISO reforms that would better capture the value of small DERs and the value of DR for load shaping, shifting, and shimmying.
- Enacting PIMS that focus on DERs and would examine:
 - The measures to be considered;
 - The metrics used to determine progress;

- The baseline from which progress for each measure is calculated;
 - The target to be achieved over what period of time;
 - Whether the measure is established for reporting purposes or whether there is an incentive and/or penalty attached; and,
 - The amount and structure of any incentive and/or penalty, if applicable.
- Develop rules and regulations governing the terms and conditions of service to ensure that appropriate consumer safeguards are in effect; and,
 - Establishing a certification requirement for ARCs.

Setting up these proceedings will create a useful roadmap that the Commission can employ to implement Act 1078. It has the potential to help lower energy costs and increase efficiency in Arkansas while creating a more resilient and modern grid.

Appendix A: Certification of Aggregators of Retail Customers⁸⁹

A) SECTION 1 - DEFINITIONS

- 1) "Aggregator of retail customers" means a person that aggregates demand response from retail customers for the purpose of marketing, selling, or marketing and selling the aggregated distributed energy resources to an electric public utility; or into a wholesale electricity market. It does not include: an electric public utility to the extent that it engages in distributed energy resources programs or distributed energy resources aggregation activities with the retail customers in its own service territory as certificated by the Arkansas Public Service Commission; or a municipally owned electric utility or consolidated municipal utility improvement district to the extent that it engages in demand response programs or distributed energy resources aggregation activities with the retail customers in its own service territory.
- 2) "Aggregation" means combining the electric load of multiple retail customers through an agreement with the customers for the purpose of marketing, selling or marketing and selling the aggregated demand response.
- 3) "Applicant" means a person who files an application for certification or certification renewal under this chapter.
- 4) "Application form" means a form, approved by the Commission, that an applicant seeking certification or certification renewal as an aggregator of retail customers shall

⁸⁹ To create these model rules, RAP reviewed the Competitive Retail Electric Service Provider certification requirements enacted by the Public Utilities Commission of Ohio and modified them to create a model rule appropriate for the certification of ARCs.

file with the Commission as set forth in this chapter.

- 5) "Commission" means the Arkansas Public Service Commission.
- 6) "Filing under seal" means personally delivering to the Commission's docketing division a sealed envelope containing information intended to be kept proprietary and confidential. This action must be accompanied by the filing and docketing of a "motion for protective order," pursuant to Commission rules.
- 7) "Public utility" shall have the meaning set forth in § 23-1-101 (9) of the Arkansas Code.

B) SECTION 2 – REQUIREMENT TO OBTAIN CERTIFICATION

- 1) Any aggregator of retail customers which intends to engage in the marketing, selling, or marketing and selling of aggregated customer demand in this state shall obtain a certificate to operate from the Commission prior to commencing operations.
- 2) The Commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.
- 3) No person shall offer, contract, provide, market or sell aggregated services in this state without a valid certificate.

C) SECTION 3 – APPLICATION FOR CERTIFICATION

- 1) An application for certification shall be completed on forms supplied by the Commission. The application forms shall provide for sufficient information to enable the Commission to determine an applicant's managerial, financial, and technical capability to provide the service it intends to offer and its ability to comply with any Commission rules or orders that pertain to the applicant.
- 2) The applicant shall be required to complete the application form in its entirety including any and all attachments, affidavits, and other documentation that may be specified in the form at the time an application is filed.
- 3) Aggregators of retail customers shall file general, managerial, and financial information as set forth in the application. This information includes but is not limited to:
 - a) Ownership and organizational descriptions.
 - b) Managerial experience and capabilities.
 - c) Credit ratings and relevant financial information, including financial statements, financial arrangements, and forecasted financial statements.
 - d) Financial capability as depicted on publicly available information and applicable credit ratings.

- e) Statements as to whether the applicant's certification has ever been revoked or suspended, or if there are pending or past regulatory or judicial actions or findings against the applicant, or past rulings finding against the applicant.
- 4) An applicant for certification or certification renewal shall file a completed and notarized original application signed by a principal officer of the applicant and shall provide the required number of conformed copies, including all supporting attachments and affidavits, with the Commission's docketing division.
- 5) The date that the Commission's docketing division stamps an application received shall serve as the official filing date with the Commission.
- 6) The Commission may deny without prejudice any application that is not complete or does not include the attachments, documentation, and affidavits required by the application form.
- 7) All aggregators of retail service shall include in their certification application, the name, telephone number, and electronic mail address of a contact person who will respond to Commission concerns pertaining to consumer complaints.

D) SECTION 4 – AFFIDAVITS

- 1) In addition to all other affidavits required in this rule, each applicant shall submit with its application, affidavits attesting that:
 - a) The information provided by the applicant on its application form and supporting attachments is complete, true, and accurate to the best knowledge of the applicant.
 - b) The applicant will timely file an annual report of its intrastate gross receipts, gross earnings.
 - c) The applicant will timely pay any assessment made pursuant to Arkansas law.
 - d) The applicant will comply with all applicable Commission rules or orders.
 - e) The applicant will cooperate with the Commission and its staff in the investigation of any consumer complaint regarding any service offered or provided by the applicant.
 - f) The applicant will consent to the jurisdiction of the Arkansas Commission and courts and the service of process.

E) SECTION 5 – CERTIFICATION RENEWAL

- 1) Any aggregator of retail customers that fails to file an application for certification renewal prior to the expiration date on the certificate must file a new application for certification in a new case and may request, no later than sixty days after the expiration

date on the certificate, to extend its previous certificate during the pendency of the new application review.

F) SECTION 6 – MOTIONS

- 1) Motions filed by an applicant must be filed by an attorney authorized to practice law in the state of Arkansas.
- 2) An out-of-state attorney may seek permission to appear *pro hac vice* before the Commission in any case upon the filing of a motion. Motions shall include all of the information and documents required by the Arkansas Supreme Court.

G) SECTION 7 – PROTECTIVE ORDERS

- 1) An applicant may file any financial statements under seal. If these exhibits are filed under seal, they will be afforded protective treatment for a period to be determined by the Commission based on applicant's request.
- 2) An applicant may file a motion for a protective order covering information not covered under paragraph (A) of this rule. The Commission shall determine the period for which protective treatment shall be granted.
- 3) At the expiration of the period provided for in paragraphs (A) and (B) of this rule, the information will be automatically released into the open record.
- 4) An applicant may file to extend the period for which a protective order is in effect.

H) SECTION 8 – APPLICATION APPROVAL OR DENIAL

- 1) If the Commission does not act upon an application for certification or certification renewal within forty-five days of the filing date, the application shall be deemed automatically approved.
- 2) Upon good cause shown, the Commission, or a hearing officer appointed by the Commission, may suspend an application.
- 3) If the Commission, or an attorney examiner appointed by the Commission, has acted to suspend an application, the Commission shall:
 - a) Docket its decision, and notify the applicant of the reasons for such suspension and may direct the applicant to furnish any additional information as the Commission deems necessary to evaluate the application.
 - b) The Commission shall then act to approve or deny the application within forty-five days of the decision referenced in (a) above or within forty-five days of receipt of additional information required from the applicant, if applicable, whichever date is later.

- c) At its discretion, set the matter for hearing.
 - 4) In evaluating an application, the Commission shall consider the information contained in the applicant's application, supporting attachments and evidence, and recommendations of its staff.
 - 5) The Commission shall approve an application if it finds that all of the following are true:
 - a) The applicant is managerially, financially, and technically fit and capable of performing the service it intends to provide.
 - b) The applicant is managerially, financially, and technically fit and capable of complying with all applicable Commission rules and orders.
 - c) The applicant is able to provide reasonable financial assurances sufficient to protect electric distribution utility companies and the customers from default.
 - 6) When the Commission approves an application, it will notify the applicant that its application has been approved and will issue the applicant a numbered certificate that the applicant can provide aggregation service and the dates for which the certificate is valid.
 - 7) Unless otherwise specified by the Commission, an aggregator of retail customers initial or renewal certificate is valid for a period of two years, beginning and ending on the dates specified on the certificate.
 - 8) If the Commission denies in whole or in part, an application, it will notify the applicant that its application, or parts of its application, have been denied, including the reason(s) for such denial.
- I) SECTION 9 – MATERIAL CHANGES TO BUSINESS OPERATION
- 1) An aggregator of retail customers shall promptly inform the Commission of any material change to the information supplied in a certification or certification renewal application within thirty calendar days of such material change and shall file such notice under the docket number assigned to it in its initial certification or most recent certification renewal application, whichever is the most recent.
 - 2) After notice and an opportunity for a hearing, the Commission may suspend, rescind, or conditionally rescind an aggregator of retail customer's certificate if it determines that the material change will adversely affect the aggregator of retail customer's fitness or ability to provide the services it is certified to provide.
 - 3) Material changes to the information contained in or supplied with a certification or certification renewal application include, but are not limited to, the following:
 - a) Any significant change in ownership (being an ownership interest of 5 percent or more) of the applicant.
 - b) An affiliation or change in affiliation with an electric utility in this state.

- c) Retirement or other long-term changes to the operational status of the applicant.
 - d) The applicant's bond rating falls below BBB as reported by Standard & Poor's, or below Baa3 as reported by Moody's investors service.
 - e) The applicant has or intends to file for reorganization, protection from creditors, or any other form of bankruptcy with any court.
 - f) Any judgment, finding, or ruling by a court or regulatory agency that could affect the applicant's fitness or ability to provide service in this state.
- 4) Applicant shall promptly report any change in the contact person, email address, business address, or telephone/fax number for staff use in investigating complaints.
 - 5) Applicant shall promptly report any change in the contact person, business address, or telephone/fax number for staff use in investigating regulatory or emergency matters.
 - 6) Applicant shall promptly report any change in the business address, or toll-free telephone/fax number for customer service and complaints.
 - 7) Applicant shall promptly report any change in the applicant's name or any use of a fictitious name.

J) SECTION 10 – TRANSFER OR ABANDONMENT OF A CERTIFICATE

- 1) An aggregator of retail customers shall not transfer its certificate to any person without prior Commission approval.
- 2) An aggregator of retail customers may apply for Commission approval to transfer its certificate by filing a certificate transfer application.
- 3) A transfer application shall be automatically approved after forty-five days after filing, unless the Commission acts to suspend or reject the application.
- 4) An aggregator of retail customers shall not abandon the service(s) it provides under a certificate without filing an abandonment application and without Commission approval and shall be obligated to fulfill the terms of all existing contracts with customers or assign such contracts to another certified aggregator of retail services prior to abandoning service.
- 5) Abandonment applications shall be filed at least ninety calendar days prior to the effective date on which the aggregator of retail services will cease providing service.
- 6) At least ninety calendar days prior to abandoning service, the aggregator of retail customers shall provide written notice to each electric utility in whose certified territory it operates and to any entity to whom it sells the product of its customers, of its intent to cease providing service. That notice shall reflect that the aggregator of retail customers has filed an abandonment application with the Commission.
- 7) (3) At least ninety calendar days prior to abandoning service, an aggregator of retail

customers shall provide written notice to its customers and the Attorney General's office of its intent to abandon service. Such notice shall indicate the aggregator of retail customers' intent to fulfill or assign customer contracts, including the effective date of such assignment, the effective date it will cease to provide service, and should identify the Commission's toll-free number as well as the number through which hearing and speech impaired customers may contact the Commission. That notice shall also provide instructions to the customers on how they may obtain replacement service(s).

- 8) The aggregator of retail services shall also provide notice of its abandonment to its existing customers by separate message that is mailed or otherwise directly delivered to the customer. Abandonment notices shall begin at least ninety calendar days prior to the effective date of the abandonment and shall continue to provide such notice on all subsequent monthly statements until the service is abandoned.
- 9) If the Commission does not act upon the application within ninety calendar days of the filing date, the application shall be deemed automatically approved on the ninety-first day after the official filing date.

K) SECTION 11 – CERTIFICATION SUSPENSION, RECISSION OR CONDITIONAL RECISSION

- 1) After notice and the opportunity for a hearing, the Commission may, upon its own motion or upon complaint, suspend, rescind, or conditionally rescind an aggregator of retail customers' certificate, in whole or in part, for good cause shown.
- 2) If the Commission suspends an aggregator of retail customers' certificate:
 - a) The Commission shall notify the aggregator of retail customers of the reasons and effective dates for such suspension and specify the actions, including associated time frames, that the aggregator of retail customers shall be required to take in order to have the suspension lifted.
 - b) The aggregator of retail customers shall continue to provide all services it is obligated to provide under contract to its existing customers but it shall not advertise, offer, or contract to provide any new services to existing customers nor advertise, offer, or contract to provide any services to potential customers during the suspension, unless the Commission orders otherwise. Such suspensions and related prohibitions against advertising, offering, or entering into contracts apply statewide unless otherwise ordered by the Commission.
- 3) If the Commission conditionally rescinds an aggregator of retail customers certificate:
 - a) The Commission will delineate the specific conditions that the aggregator of retail customers must meet and establish a date by which the conditions must be met in order for the aggregator of retail customers to avoid permanent rescission of its certificate.

- b) Unless otherwise ordered by the Commission, the aggregator of retail customers shall continue to provide all services it is obligated to provide under contract to its existing customers, but it shall not advertise, offer, or contract to provide any new services to existing customers nor advertise, offer, or contract to provide any service to potential customers during the pendency of the conditional rescission.
- 4) If the Commission rescinds an aggregator of retail customers' certificate:
- a) The Commission will notify the aggregator of retail customers of the reasons for and effective date of such rescission.
 - b) Upon the effective date specified by the Commission, an aggregator of retail customers whose certificate has been rescinded shall cease providing all services for which it is no longer certified to provide.
 - c) Prior to the effective date of the certificate rescission, an aggregator of retail customers that provides services to customers shall cooperate fully with each electric utility in whose certified territory it provides such service to ensure that its customers will be served by another certified aggregator of retail customers or by the electric utility on and after the effective date of the certificate rescission as necessary.
- 5) Prior to the effective date of the certificate rescission, an aggregator of retail customers whose certificate has been rescinded shall provide a written notice to each of its customers that indicates that its certificate has been rescinded and specifies the date(s) it will cease to provide service. Such notice shall be provided to the Commission staff for its review and to the electric utility prior to customer dissemination. Such notice shall also inform customers as to whether another aggregator of retail customers or the utility will provide the services set forth in the customer's contract with the aggregator of retail customers whose service is being rescinded, as necessary.
- 6) Reasons that the Commission may suspend, rescind, or conditionally rescind an aggregator of retail customers' certificate include, but are not limited to:
- a) An aggregator of retail customers' failure to timely pay any assessment made pursuant to Arkansas law.
 - b) An aggregator of retail customers' failure to timely file an annual report of its intrastate gross receipts pursuant to Arkansas law.
 - c) A finding by the Commission that an aggregator of retail customers has materially underreported its intrastate gross receipts required by Arkansas law.
 - d) A finding by the Commission that any information reported to the Commission subsequent to granting a certificate adversely affects an aggregator of retail customers' fitness or capability to provide any service covered by its certificate.
 - e) A finding by the Commission that an aggregator of retail customers deliberately

omitted information or knowingly provided false information on a certification or certification renewal application, including supporting attachments.

- f) A finding by the Commission that an aggregator of retail customers has provided services to a customer without being certified by the Commission to provide such service.
- g) A finding by the Commission that an aggregator of retail customers has violated any applicable Commission rule or order.
- h) A finding by the Commission that an aggregator of retail customers has failed to consent to the jurisdiction of the courts of this state or has failed to designate an agent to accept service of process pursuant to Section (D)(1)(f) above.
- i) A finding by the Commission that an aggregator of retail customers has engaged in anti-competitive behavior.
- j) A finding that an aggregator of retail customers has failed to maintain appropriate default security or has otherwise failed in a material way to adhere to requirements contained in an electric utility's tariff governing an aggregator of retail customers' requirements as approved by the Commission.
- k) A finding by the Commission that an aggregator of retail customers has failed to comply with state laws or rules designed to protect consumers in this state or has otherwise engaged in any fraudulent, misleading, or unfair practice.

L) SECTION 12 – FINANCIAL SECURITY

- 1) Pursuant to a tariff filed with the Commission, an electric utility may require an aggregator of retail customers to issue and maintain financial security with the electric utility to protect the electric utility and its customers in the event that an aggregator of retail customers fails, in whole or in part, to deliver contracted services.



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