

Foundations for an Intelligent Energy Future: Demand Response Potential in Louisiana

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Introduction

Modern lives run on electricity. With the lift of a switch, lights come on, and machines go to work. But because electricity cannot be stored in meaningful quantities yet, power must be instantaneously generated the moment it's needed. Ensuring electricity supply meets electricity demand every second of the day is a delicate balancing act — requiring extensive planning and coordination.

Historically, electricity generators followed demand — turning up or down — to meet any changes in customers' electricity needs. But with the recent up-tick in the share of renewable generators used to supply electricity, balancing fluctuations in both supply and demand is increasingly challenging. Dispatching generators to change supply is just one side of the equation. The demand side of the equation can also be changed — with demand response (DR). DR incentivizes customers to temporarily shift or change their electricity consumption in response to price or other signals.¹ For example, Louisiana customers might turn their thermostats up a couple of degrees on a hot summer day — when electricity prices are high — to save both energy consumption and money.

Due to its energy- and cost-saving potential, DR participation is growing quickly in some wholesale electricity markets. As a case in point, DR capability in the Midcontinent ISO (MISO) increased by 23.7% from 2016 to 2018.² Nationwide, DR participation grew by about 3% in 2017 (Foster, 2018). Increasing concerns with respect to the environment and electricity grid reliability — due to increasing amounts of renewable resources — create a need for enhanced DR participation, particularly from energy-intensive industrial customers (Shoreh et al., 2016).

Louisiana — one of the most energy-intensive states in the nation — has a unique opportunity to increase DR participation among its industrial customers. DR offers numerous benefits, as described in Section 1, but implementing new DR programs is a challenging prospect for utilities, customers, and regulators. As Louisiana examines its options for increasing DR participation, it is useful to build on lessons learned from other successful DR programs. As DR program design is not a one-size-fits-all approach, Section 2 covers common classifications of DR programs and how they are used to achieve demand reductions. Section 3 discusses the need for increased DR in Louisiana, and the benefits it can bring to Louisiana customers. Section 4 reviews current DR programs that have been implemented in Louisiana, and compares their participation and performance in relation to other states in the MISO footprint. Based on this pre-COVID-19 evaluation, recommendations for improvement based on other successful programs are provided.³

Because Louisiana is part of the larger MISO wholesale market, increased DR participation in Louisiana can create additional benefits for customers across the MISO footprint. Section 5 provides an overview of current challenges within the larger MISO footprint that could be ameliorated with increased DR participation from Louisiana's resources. Section 6 concludes and provides recommendations for further research to help bring Louisiana's DR to its full potential.

¹ The Federal Energy Regulatory Commission (FERC) defines DR as: "Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

² 2018 State of the Market Reports for the MISO Electricity Markets, Table 15 at 91. https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf (accessed 9/16/2019).

³ The analyses in this report are based on data from the pre-coronavirus 2019 (COVID-19) timeframe.

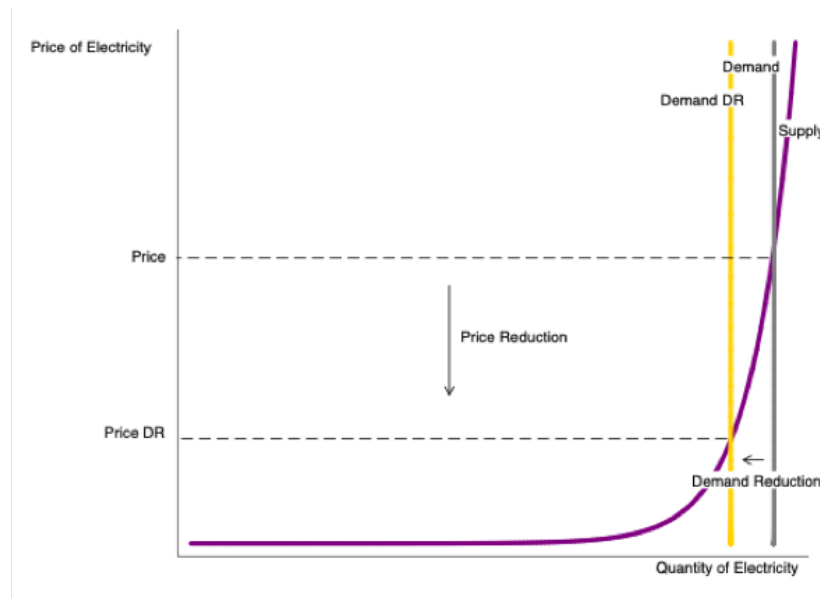
1 | What are the Benefits of Demand Response?

DR growth can be attributed to the benefits it creates for customers, for electricity markets, and for managing the electricity grid. DR makes customers more price-sensitive, better aligning their consumption with their willingness-to-pay for electricity. Incentivizing customers to reduce their electricity consumption when prices are high, or power system reliability is a concern, helps to reduce peak demand, lowering electricity market prices and power system costs (Qdr, 2006).

Typically, electricity customers are not price-responsive because they pay regulated retail rates that are based on average electricity costs, rather than the time-varying wholesale price of electricity. This disconnect results in an inelastic customer demand in electricity markets. By incentivizing customers to reduce their demand in periods when prices are high — either through making them more price-sensitive or responsive to signals from the market operator — cost savings can be achieved. Figure 1 shows that by reducing inelastic customer demand, overall electricity prices (and costs of electricity production, from the supply curve) are reduced — saving market participants and customers money.

In addition to reduced electricity prices, and reduced electricity purchases from high-cost suppliers, DR can permanently reduce peak demand, lowering the need for system-wide power generation and transmission capacity over time (Qdr, 2006). When utilities need to build less capacity to meet peak electricity demand, customers save money.

Figure 1: Demand Response Price Reduction Benefits



Notes: Reproduction of DR Illustration in “Benefits of DR in Electricity Markets and Recommendations for Achieving Them.” Source: DOE, 2006.

DR also helps improve electricity grid and market management by helping the grid run more reliably and efficiently. DR spurs reliability benefits from lowering the likelihood of forced outages during periods of high demand or extreme weather events, reducing the potential for price spikes, demand shedding, and even electricity blackouts (Qdr, 2006). By reducing peak demand, DR also

limits a pivotal supplier's ability to exercise market power (raise electricity prices) in the short run — encouraging more competitive and efficient markets with less variable prices.

While historically DR was utilized by regulated utilities to prevent blackouts or control costs during peak demand periods, in organized wholesale markets, DR has additional benefits. DR can reduce price volatility, improve the elasticity of demand, and reduce energy prices for larger numbers of customers across the organized market footprint (Hurley et al., 2013). But in order to achieve these benefits, both the Federal Energy Regulatory Commission (FERC) and state regulators have had to remove barriers to participation, such as limitations on participation and remuneration, in order to enable increased levels of DR.

2 | Demand Response Classification

Options for customers to participate in DR typically fall under two main categories: incentive-based programs and price-based programs (Qdr, 2006). Incentive-based programs aim to reduce customer demand during critical or peak demand periods by paying customers for their demand reductions. Price-based programs aim to reduce electricity use during high-price periods by reflecting real-time wholesale electricity costs in customer rates.

2.1.1 Incentive-based Programs

Classical incentive-based programs include direct load control and interruptible/curtailable load programs. Market-based, incentive-based programs include emergency DR, demand bidding, capacity market, and ancillary services programs that are facilitated through an organized wholesale market (Qdr, 2006; Albadi and El-Saadany, 2008). Incentive-based programs reward participation with payments — typically, bill credits or discount rates for classical programs, and performance-based monetary payments for market-based programs (Albadi and El-Saadany, 2008). Incentive-based programs typically measure success in terms of percentage and actual peak demand reduction (Albadi and El-Saadany, 2008).

The primary challenge with incentive-based programs is determining the baseline from which to pay customers for their demand reduction. Typically, the baseline is set from customers' past behavior, which introduces two potential problems: adverse selection and moral hazard (Borenstein et al., 2002). Adverse selection occurs when customers volunteer for the program because they know their electricity consumption will be lower than the baseline period—allowing them to be paid for demand reduction that would have occurred anyway. Moral hazard occurs when customers know they can affect their baseline — discouraging conservation when payments are not in effect because customers know it lowers their baseline (Borenstein et al., 2002).

Incentive-based programs can also have distributional implications if the money for demand-reduction payments is raised through raising all customers' rates (Borenstein et al., 2002). Nevertheless, grid operators in organized wholesale markets have been more inclined to use incentive-based DR resources as they provide more certainty that needed demand reductions could be achieved if necessary (Borenstein et al. 2002).

Figure 2: Demand Response Inducing Price-Elasticity of Demand



Notes: Illustration based on the simplified effect of DR on electricity market prices. Source: Albadi and El-Saadany (2008).

2.1.2 Price-based Programs

Price-based programs include static pricing programs (time-of-use rates), and dynamic pricing programs (real-time pricing, and critical-peak pricing) (Borenstein et al., 2002; Qdr, 2006). Price-based programs aim to reduce peak demand through making customers more price sensitive. Programs encourage customers to purchase less electricity when prices/rates are high, and more electricity when prices/rates are low, essentially making a customer's power demand more elastic, as shown in Figure 2. Because price-based programs make demand more elastic, in addition to peak load reduction, performance is measured using the price elasticity of demand, which measures the customer's percentage change in power demanded relative to the percentage change in electricity price ($\epsilon_D = \Delta Q / \Delta P$) (Albadi and El-Saadany, 2008).

The challenge with price-based programs is to balance the tradeoff between giving customers more advance notice of prices, which reduces their price volatility, and having prices accurately reflect real-time electricity costs (Borenstein et al., 2002). Giving customers more accurate price signals also requires appropriate metering technology and communication infrastructure.

Price-based programs fall under the umbrella of static or dynamic. Static programs, often called time-of-use (TOU) programs, set prices at pre-determined rates for certain hours and days. Prices are static because there is a long length of time between the price being set and the actual price being incurred, making these programs less costly to implement, but also less reflective of actual supply and demand conditions (Borenstein et al., 2002). Dynamic-pricing programs allow prices to change on short notice — every hour for real-time pricing, or with limited notice during critical peak periods — making them costlier to implement, but also more effective at capturing variation in prices (Borenstein et al., 2002).

Price-based programs can also have distributional impacts. Customers who tend to consume more electricity during peak periods (such as using the air-conditioner during hot summer days) will pay

a higher average price than customers who have a relatively flat demand (such as using power for industrial production) (Borenstein et al., 2002). Customers with relatively flat demand, or demand whose peak does not coincide with system peak may be more likely to sign up for and benefit from price-based programs, lowering utility revenue as these customers effectively subsidize peak-consuming customers under flat-rate structures (Borenstein et al., 2002).

A summary of various DR programs, with descriptions of typical participation options provided by the Department of Energy and categorized according to Borenstein et al. (2002), and Albadie and El-Saadany (2008), is shown in Table 1. DR programs are further classified as dispatchable or non-dispatchable. Dispatchable DR programs allow the system operator to curtail participants' demand in response to reliability events or market outages, whereas non-dispatchable DR programs are voluntary, and rely on participants to respond to price signals (Gagne et al., 2018).

Table 1: Demand Response Options

Price-Based Options (Non-Dispatchable)	Incentive-Based Options (Dispatchable)	
Static:	Classical:	Market Based:
<p>Time-of-use (TOU): a rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods.</p>	<p>Direct load control: a program by which the program operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers.</p>	<p>Demand Bidding/Buyback Programs: customers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one megawatt (MW) and over).</p>
Dynamic:		<p>Emergency DR Programs: programs that provide incentive payments to customers for load reductions during periods when reserve shortfalls arise.</p>
<p>Real-time pricing (RTP): a rate in which the price for electricity typically fluctuates hourly, reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis.</p>	<p>Interruptible/curtailable (I/C) service: curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties may be assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.</p>	<p>Capacity Market Programs: customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so.</p>
<p>Critical Peak Pricing (CPP): CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, a provision is made for replacing the normal peak price with a much higher CPP-event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).</p>		<p>Ancillary Services Market Programs: customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.</p>

Notes: DR program summaries are from the U.S. Department of Energy (QDE, 2006). Categorization of programs is based on those in Borenstein et al. (2002) and Albadie and El-Saadany (2008).

3 Can Louisiana Benefit from Demand Response?

Louisiana is one of the most energy-intensive states in the nation, ranking first in terms of total per-capita energy consumption in 2016—mostly due to its energy-intensive chemical, petroleum, and natural gas industries.⁴ This energy-intensive industrial sector is forecast to grow with 125 projects across 12 industries, valued at \$32 billion, expected to be constructed over the next three years.⁵

A growing, energy-intensive industrial sector means growing industrial-sector electricity demand. In power systems, enough generation capacity must be available to meet annual peak demand for that system.⁶ Entergy Louisiana, LLC (ELL), a utility that serves 1.08 million customers across 58 Louisiana parishes,⁷ forecasted its peak load to increase 7.4%, or 700 MW, from 2019 to 2038, despite flat-to-declining usage per customer in residential and commercial demand sectors.⁸ Figure 3 is a graph of ELL's long-term capacity needs. The red line depicts ELL's forecast for capacity needs — based on peak demand and a planning resource margin — less ELL's current generation portfolio. This load forecast requires an additional seven gigawatts (GW) of electricity generation capacity over the next 20 years, due to planned generation retirements (of 5,800 MW), expiring purchase power agreements,⁹ and growth in industrial demand.

To put the capacity needs forecasted by ELL into an economic perspective, the cost to meet ELL's expected demand is in the neighborhood of 26.5 billion dollars,¹⁰ with 1.85 billion attributed to industrial demand growth. While the bulk of this cost is due to an aging power generation fleet, with large industrial customers driving demand growth, incorporating DR into this sector could potentially reap large savings for Louisiana customers.

Increasingly, industrial processes, HVAC, and transportation are being electrified, leading large industrial customers to focus on power procurement (Shreve, 2019). DR has the attractive benefit that it can reduce power prices, through reducing or shifting demand, creating a value proposition for large industrial customers. But industrial customers have to balance potential savings from DR with its costs. DR options for industrial customers typically include reducing or stopping production during peak demand, and/or utilizing backup power during peak demand—provided the industrial customer has the appropriate environmental permits (Gagne et al., 2018).

Louisiana Energy Users Group (LEUG), an association of 24 large industrial companies in the chemical manufacturing, refineries, industrial gasses, pulp and paper, and pipeline industries, emphasizes that electricity costs are a significant amount of overall production costs and an important factor in industries deciding where to expand and build new plants. LEUG is currently seeking to obtain greater flexibility for industrial customers in Louisiana to obtain their own power outside of their traditional utility service area. Options proposed include industrial customers building their own combined heat and power (CHP) generation, entering long-term power purchase contracts with

⁴ "Louisiana and Wyoming consume the most energy per capita; Rhode Island, New York the least." U.S. Energy Information Administration. <https://www.eia.gov/todayinenergy/detail.php?id=37012> (accessed 10/9/2019).

⁵ 1012 Industry Report, Q3 2019 at 13. https://issuu.com/batonrougebusinessreport/docs/10_12_industry_report__q3_2019_ (accessed 10/9/2019).

⁶ Although Entergy Louisiana is part of the Midcontinent Independent System Operator, long-term capacity requirements are based on its own installed capacity. Entergy Data Assumptions and Study Description for the 2019 ELL Integrated Resource Plan, at 10. https://www.entropy-louisiana.com/userfiles/content/irp/2019/ELL_IRP_2019_Assumptions.pdf (accessed 10/9/2019).

⁷ <https://www.entropy-louisiana.com/about-us/> (accessed 10/9/19).

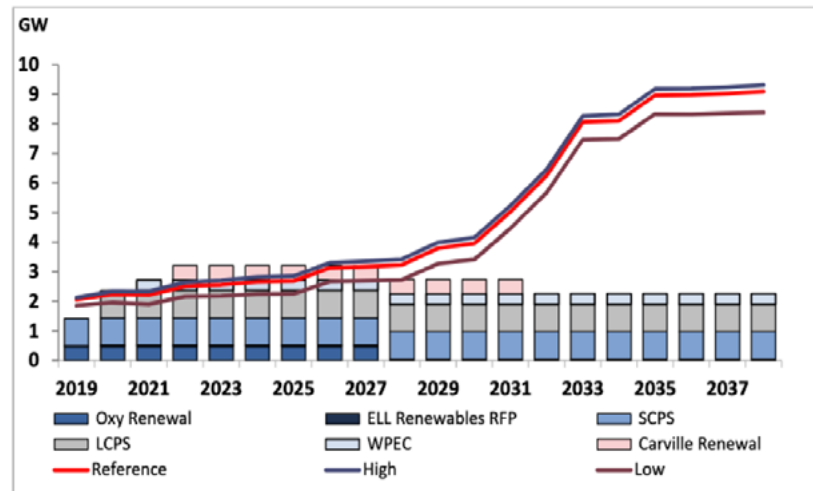
⁸ Entergy Louisiana, LLC reference load is forecasted to be 10,133 MW in 2019 and 10885 MW in 2038. Entergy Data Assumptions and Study Description for the 2019 ELL Integrated Resource Plan, at 80. https://www.entropy-louisiana.com/userfiles/content/irp/2019/ELL_IRP_2019_public.pdf (accessed 10/9/2019).

⁹ Entergy 2019 Integrated Resource Plan, at 6. https://www.entropy-louisiana.com/userfiles/content/irp/2019/ELL_IRP_2019_public.pdf (accessed 10/9/2019).

¹⁰ Entergy 2019 Integrated Resource Plan, at 65. https://www.entropy-louisiana.com/userfiles/content/irp/2019/ELL_IRP_2019_public.pdf (accessed 1/09/2020).

other utilities or private power generating entities, and buying power directly from MISO. The LEUG is also advocating for new industrial tariff options that include interruptible service, and real-time pricing options to purchase stand-by service from wholesale markets to facilitate DR for those industrial customers choosing to remain with a particular utility.¹¹

Figure 3: Entergy Louisiana Long-Term Capacity Needs



Notes: ELL's forecast for capacity needs is based on peak demand and a planning resource margin, less their current generation portfolio. The reference forecast is the red line, which increases over time as demand grows, and some of Entergy's generators retire. Demand growth is driven by planned generation retirements, but also by industrial load growth (5.8 GW retiring, 700 MW load growth). Demand side management is considered but only for residential and commercial customers.

Source: ELL's 2019 Integrated Resource Plan

Focusing on large industrial users could save Louisiana customers money, as large demand reductions can be obtained from a small number of demand-response participants (Gagne et al., 2018). Barbose et al. (2004) found that large industrial customers are also the most likely segment of customers to respond to real-time price incentives, as these customers are typically used to being on interruptible/curtailable demand contracts, able to reschedule energy-intensive industrial processes, and have their own on-site backup generation. Further, Kiliccote (2010) found that in California, industrial facilities participating in automated DR¹² programs tended to be larger and reduce a higher percentage of their demand, reducing peak demand on average by 14% to 33% from 2006 to 2007, making up more than half the savings of DR for California utilities.

4 Louisiana's Demand Response Options

Most of Louisiana is within the MISO market footprint. MISO allows three types of registered market participants to participate in its DR programs: Load Serving Entities (LSEs), Aggregators of Retail Customers (ARCs), and end-use customers that are registered as market participants. MISO utilizes DR to reduce demand in the energy market (economic DR), provide ancillary services (operating

¹¹ Louisiana Public Service Commission Docket No. S-34426, dated February 13, 2019. Louisiana Public Service Commission, ex parte; *Louisiana Energy Users Group Comments on LPSC Staff Report*.

¹² Enabled by an automated DR signaling system named Open ADR (Open Automated Demand Response), which used utility-provided signals to automatically trigger customers' pre-programmed DR strategies (Kiliccote, 2010).

reserve DR), reduce demand during emergency situations (emergency DR), substitute for generating capacity (planning resources DR) and substitute for transmission.¹³ Potential DR participation options offered in the MISO market are summarized in Table 2.

Currently, MISO has nearly 13 GW of DR capability, but only a small amount of that capability is actually used due to its excess capacity margins.¹⁴ However, MISO expects to call on these resources more frequently in the future due to tightening capacity reserve margins, and the increasing share of renewable resources in MISO’s resource mix.¹⁵

Table 2: Demand Response Participation Options in MISO

DR Options in MISO
Incentive-Based Options (Dispatchable)
Market Based:
<p><i>Demand Bidding/Buyback Programs:</i></p> <p>Economic DR Qualifying market participants may submit Demand Response Resource (DRR) energy offers into the Day-Ahead Market and/or the Real Time Market. Offers that clear the market follow MISO dispatch instructions and receive the Locational Marginal Price (LMP) for their load reductions. There are two types of qualifying DRR: Type 1 can provide a fixed, pre-specified quantity of physical demand reduction. Type 2 can supply a range of physical demand reduction or behind-meter-generation.</p> <p><i>Emergency DR Programs:</i></p> <p>Emergency DR Market participants voluntarily notify MISO they are willing to provide DR in emergency events through MISO’s Emergency Demand Response Initiative (EDR) and register as an EDR resource. Market participants offer how much and at what cost they are willing to curtail power the next day.</p> <p><i>Capacity Market Programs:</i></p> <p>Planning Resources DR DR resources can qualify as load modifying resources (LMRs, or planning resources) provided they can respond to emergency events upon MISO instruction.¹⁶ DR resources can qualify as a capacity resource if they are able to reduce their demand at MISO’s peak. Both planning and capacity resources that clear the Planning Resource (Capacity) Auction commit in advance to using the resources to reduce gross demand on the system when instructed to do so. Planning and capacity resources receive zonal resource credits and can be used to reduce a utility’s planning reserve requirements.</p> <p><i>Ancillary Services Market Programs:</i></p> <p>Operating Reserves Demand Response Market participants qualifying as a DR resource can provide regulating reserve, spinning reserve, supplemental reserve and ramp capability product services, provided they are technically capable to provide the service. Market participants provide additional pricing for these services with their energy offers.</p>

Notes: Program descriptions are based on MISO Business Practices Manual DR, Manual No. 026 (2018). DR resources can also be used to resolve transmission issues through participating as a non-transmission alternative resource, see BPM-026 for further information.

¹³ MISO Business Practices Manual DR, Manual No. 026 (2018). MISO Business Practices Manual DR, Manual No. 026 (2018). <https://www.misoenergy.org/legal/business-practice-manuals/> (accessed 10/18/2019).

¹⁴ “MISO State of the Market Report 2018”, at p. 92. https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf (accessed 1/10/2020).

¹⁵ MISO “Load Modifying Resources: Capacity Instruments affecting Resource Availability and Need,” dated May 25, 2018, at p. 2. <https://cdn.misoenergy.org/20180531%20RSC%20Item%2009%20LMR%20Issues%20Whitepaper206830.pdf> (accessed 1/12/2020).

¹⁶ LMR(s) must be greater than or equal to 100kW, and must be available to reduce demand with no more than 12 hours advanced notice, and maintain the demand reduction for at least 4 hours. LMR can be interrupted at least 5 times during the summer season. When measuring performance of LMRs, actual demand reduction is compared to a consumption baseline of hourly average demand from the 10 days prior to an emergency event. <https://www.misoenergy.org/legal/business-practice-manuals/> (accessed 10/18/2019).

In terms of participation in MISO’s DR programs, of MISO’s nearly 13 GW of DR capability, more than half of that capability is from Load Modifying Resources (LMRs). MISO’s LMR program allows distribution utilities to reduce their planning reserve (capacity) requirements if LMRs clear MISO’s capacity auction. Among MISO’s DR participation options, this program is also growing the fastest.

Table 3: MISO Demand Response Participation

	2016	2017	2018	% Increase in Participation 2016 - 2018	% of Total 2018 DR Capability
Behind-the-Meter Generation	3,822	3,822	4,496	17.6%	35%
Load Modifying Resource	4,616	6,112	7,137	54.6%	55%
DRR Type I	525	620	621	18.3%	5%
DRR Type II	75	0	3	-96.0%	0%
Emergency DR	1,416	941	674	-52.4%	5%
Total	10,454	11,495	12,931	23.7%	100%

Notes: Program participation numbers for 2016, 2017, and 2018 are from the MISO 2018 State of the Market Report at pg. 91.

Hurley et al. (2013) found that an important driver of DR participation in wholesale markets is a mechanism that provides a steady payment in exchange for a required amount of DR, like those found in capacity market programs — a finding that rings true with MISO’s increased LMR participation. Although MISO’s participation in other types of DR lag behind its planning reserve program, potentially due to low payments for these services (Hurley, 2013), this trend could change in the near future. The replacement of retired coal and nuclear units with a mix of renewable resources, gas-fired resources, and load-modifying (DR) resources has resulted in more frequent emergency events (outages) in the MISO footprint — a trend expected to increase reliance on DR resources in the future.¹⁷

Another complication for DR participation across the MISO footprint is that MISO operates its wholesale market across several distinct balancing areas.¹⁸ This is unlike other ISOs — PJM and NYISO, for example — which operate their wholesale market across a single balancing area (Hurley, 2013). In essence, this means that although in theory MISO has access to a wider pool of DR resources to better balance demand and supply across its footprint, in practice, these resources are managed by the local, vertically-integrated utility. These utilities may have their own DR programs, but also have a different set of incentives than ISOs/RTOs, as they earn a rate of return on capital infrastructure.

Because of MISO’s balancing authority structure, in understanding Louisiana’s DR potential, it is also worthwhile to gauge participation in DR programs across other utilities within the MISO footprint. The Energy Information Administration (EIA) tracks annual participation and performance of DR programs

¹⁷ “MISO State of the Market Report 2018”, at p. 9. https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf (accessed 1/12/2020).

¹⁸ Balancing areas are essentially geographic areas within which electricity supply and demand must be balanced by the balancing authority.

Table 4: Louisiana Demand Response Participation Options

Commercial/Industrial DR Options in Louisiana	
Entergy Louisiana, LLC (ELL)	
Incentive-Based Options (Dispatchable)	
<p>Classical: Interruptible/curtailable (I/C) service: ELL has several interruptible tariffs (Schedules CS-L, ECS-L, EECS-L, EIS-I-G, IS-G, Rider 2 to LIS-L, Rider 2 to LIPS-L, and CS-I). These tariffs have been closed to new customers (most for 20 years) and limited to previously contracted amounts. In 2019, ELL introduced a Proposed Rider Experimental Interruptible Option which would allow non-residential customers to voluntarily contract with ELL to register as an LMR or DRR with MISO. Customers must have at least 2 MW of demand, and 1 MW of curtailable demand. Customers will receive a demand-based credit on monthly bills, provided performance obligations are met.²²</p>	
Market-Based Options	
<p>ELL has introduced a Proposed Rider Market Valued Demand Response Rider (MVDR) which would allow qualifying customers and aggregators of retail customers (ARCs) to participate, through ELL as the sole market participant, in MISO’s DR markets. Customers must comply with MISO market rules and remit 10% of their settlement fee to ELL, see LPSC docket no. U-35443.</p>	
Cleco Power	
Price-Based Options (Non-dispatchable)	
<p>Static: Time-of-use (TOU): Time-of-Use Choice DR program offers differentiated pricing to participating customers for on-peak and off-peak hours. Enrollment is capped at 2000 customers and is limited to residential service and non-demand general service customers.²³</p>	
Southwestern Electric Power Co.	
Incentive-Based Options (Dispatchable)	
<p>Classical: Interruptible/curtailable (I/C) service: No DR programs are currently available to Louisiana customers. SWEPCO does offer interruptible/curtailable DR programs in other states.²⁴</p>	

While proposed updates to retail tariffs to encourage DR participation are a step forward for Louisiana, there is ongoing debate regarding whether the Proposed Rule will be effective. Much of the debate centers on an important attribute of DR program design — how to increase participation in a cost-effective manner. To shed some light on this question, it’s useful to take a deeper look at Louisiana’s demand response participation and performance in comparison to other states in the MISO footprint. Opportunities for improvement are highlighted with recommendations based on the DR literature.

²² Entergy Services LLC, dated September 30, 2019. In Re: Application of Entergy Louisiana, LLC for Authorization to Implement an Experimental Interruptible Option, Rider EIO, and Related Relief. Per discussion with Entergy, if approved this option could add up to 500 MW of interruptible load, based on a 5% of peak load participation cap.

²³ <http://pscstar.louisiana.gov/star/ViewFile.aspx?id=3d747ee5-64c6-4e51-917b-7fabc3db696a> (accessed 10/19/2019). https://www.cleco.com/documents/10180/28259331/TP_TOUCH+Program_Experimental+Pilot/bd3bfa77-5775-4b85-a35d-9e4c5639d0d4 (accessed 10/19/2019).

²⁴ <http://pscstar.louisiana.gov/star/ViewFile.aspx?id=af4a4882-7a84-49dd-9b23-150a79e9e6e4> (accessed 10/19/2019).

4.1. Interruptible/Curtailable Demand Response Programs

4.1.1 Program Participation

MISO offers several incentive-based DR programs as shown in Table 2. Within the MISO footprint, over 50,000 Commercial and Industrial (C&I) customers participated in available DR programs offered by utilities in 2018, as reported in EIA Form 861, and shown in Figure 3. Based on the EIA data, Louisiana has an opportunity to improve its incentive-based demand response participation.²⁵

To achieve optimal demand response participation, Louisiana can follow best practices gleaned from other successful DR programs. In a survey of DR programs across the United States, Hurley et al. (2013) identified several key challenges to the optimal participation of DR resources. These challenges included establishing baselines from which to accurately measure DR performance, removing market barriers, such as minimum size requirements and prohibition of third-party aggregators that limit participation, and traditional utility incentive structures that do not reward DR participation.²⁶ These challenges are also relevant for the implementation of DR in Louisiana.

A selection of best practices Louisiana can leverage from other programs follows. In addition, areas for future research that could benefit Louisiana's DR implementation are also highlighted.

4.1.2 Program Incentives and Costs

For an interruptible/curtailable DR program, compensation should be based on how much customers reduce their demand from their typical consumption baseline. Figure 5 depicts an example. The black dotted line is a customer's baseline consumption, based on historical demand. The area shaded in purple is the customer's actual demand, and the area shaded in yellow is the amount the customer reduced their demand due to DR. The first challenge in valuing the demand reduction from DR is to establish an accurate baseline — a task accomplished with historical data of a customer's actual demand. The second challenge is valuing the customer's reduction in demand.

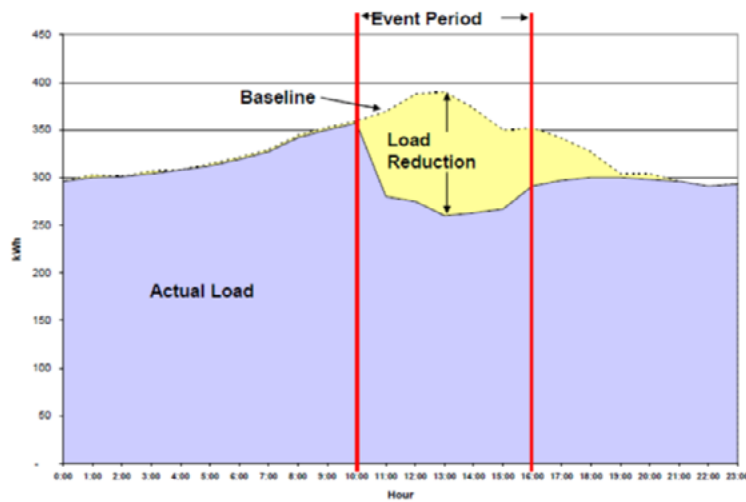
Although customers vary in their use of electricity for energy-intensive processes by customer class and industry, from the perspective of the grid operator, these differences in energy uses can be captured by a customer's 'baseline' demand profile — the typical amount of energy the customer uses. Although there are different methods for calculating customer baselines, Hurley et al. (2013) recommend that the method be reliable and feasible. Reliable methods give grid operators confidence that they will receive the change in demand they expect when they call upon the DR resource. Feasible methods allow both the customer and DR provider to comply with the DR reporting requirements, both financially and feasibly.

DR saves utilities money because reduced demand means they avoid paying for the generation, transmission, and other costs they would have otherwise incurred to meet demand. By this logic, utilities should be willing to pay up to their avoided cost of servicing demand. A lot of factors go into that calculation, but one of the most significant factors is the value of avoided capacity. Because Louisiana is part of MISO, the value of capacity is determined by MISO market prices. This value will depend on the relative abundance or scarcity of available capacity and it will vary over time.

²⁵ It is possible that more commercial and industrial customers participate in DR in Louisiana, but are not reported to the EIA. The EIA data is utilized as a benchmark to provide insight into potential opportunities for DR in Louisiana.

²⁶ For a full list of recommendations see Hurley et al. (2013).

Figure 5: Peak Demand Reduction from DR



Notes: Graph illustrates a representative customer's baseline demand and peak demand reduction. The purple-shaded region represents demand, and the yellow-shaded region represents DR reductions.

Source: NYISO baseline (NREL, 2018).

Systems with large surpluses of capacity (like MISO) have relatively low capacity market prices in the short-run. Over the long-run, when new capacity is needed to meet demand, the capacity market prices are driven by new entrants to the market — usually the cost of a new gas-fired combustion turbine facility. For this reason, forecasts of wholesale market capacity prices typically assume that those prices will trend toward the capacity cost of a new natural gas-fired CT over the long-term (Woolf, 2013). As a case-in-point, the going rate for capacity in Louisiana's zone was \$10/MW-day, and the cost of new entry for Louisiana's zone was \$228.10, based on MISO's 2018/2019 Planning Resource Auction (PRA), in the more recent 2019/2020 PRA, the going rate for capacity in Louisiana's zone was only \$2.99/MW-day.²⁷

For a local utility, the basic approach in calculating an avoided capacity value for a DR program should be to forecast the market price for capacity for each year in which the DR program will be operational. Determining this value is *incredibly important*. Too high, and the program is too costly for the utility—too low, and customers won't have an incentive to participate. At a minimum, assumptions should be transparent to all involved parties.

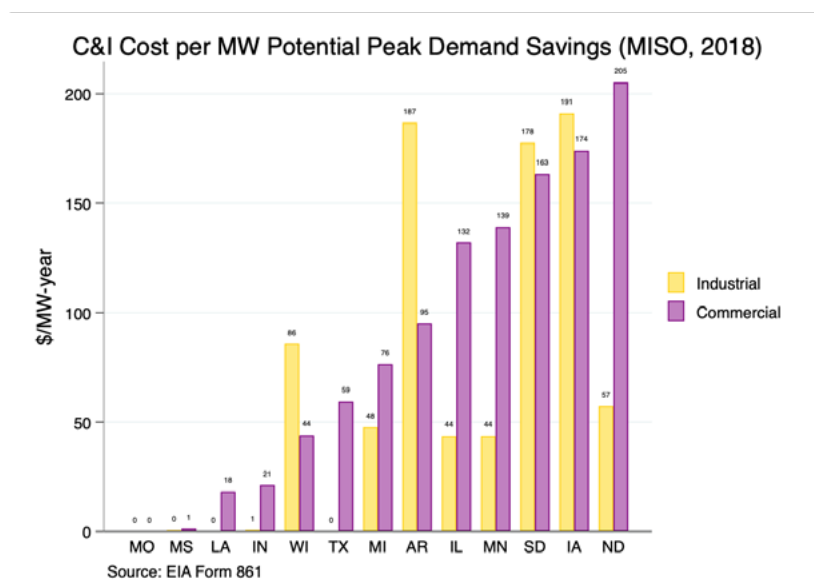
Other important avoided costs include avoided energy costs, avoided transmission and distribution costs, avoided ancillary service costs, revenues from wholesale DR programs, market price suppression effects, avoided environmental and compliance costs, avoided environmental externalities, participant bill savings, financial incentives to participate, tax credits, and other benefits like reduced price volatility or improved reliability. Industry best practices in the evaluation of DR programs follow the "California Standard Practice Manual,"²⁸ which establishes cost-effectiveness tests for demand-side program costs and benefits (Woolf, 2013).

²⁷ MISO has currently experienced low capacity prices due to some capacity market design issues as discussed in the 2018 State of the Market Report. https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf (accessed 2/27/2020).

²⁸ https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf (accessed 1/12/2020).

Figure 6 shows the cost per MW of actual peak demand reduction for various states in the MISO footprint.²⁹ The figure is made by aggregating utility-level program costs and potential demand reductions to the state level, then dividing total costs by the potential MW of reduced demand. For reference, MISO’s annual average peak demand price in 2018 — the avoided cost of energy — was \$36/MWh,³⁰ and the avoided cost of capacity from the 2018/2019 PRA was \$10/MW per day.³¹ It’s clear that states with fewer customers, as shown in Figure 3, also tended to have much lower DR costs. As a case in point, Louisiana’s industrial DR costs were \$0/MW-year, far below the avoided cost of energy and capacity. For states with larger numbers of customers, costs tended to vary by state.

Figure 6: Demand Response Cost per MW



Notes: Incentive and other costs per MW of potential peak demand saved for commercial and industrial customers at the state level

Source: EIA Form 861

Although in theory, capacity and energy costs should be set by the market, in practice, program costs and attributes vary widely — due to differences in programmatic or policy costs and benefits allowed or required in DR programs. Areas for future research include surveying best practices among utilities to determine which utility-administered DR programs work best and why. From such a survey, best practices for calculating customer baselines, and measuring and rewarding customer performance could be utilized to develop standardized methods for utilities and regulators in the MISO footprint. A second area for future research is to determine the appropriate avoided cost of capacity for utilities in Louisiana, given current capacity market valuation issues that have arisen in the MISO market, which will be discussed in Section 5.

4.1.3 Program Performance

With respect to DR performance, Figure 7 presents a DR subscribed performance index (SPI), which is

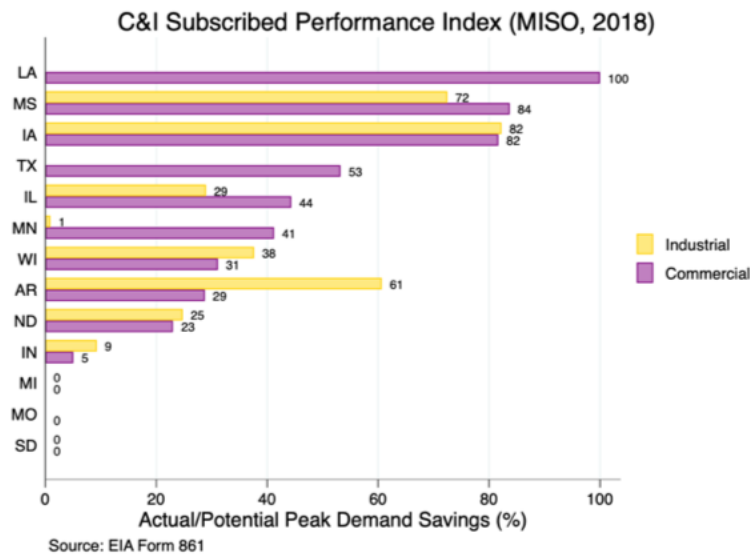
²⁹ The EIA Form 861 reports costs for DR program incentives and other costs in thousands of dollars. The EIA Form 861 also reports actual peak demand savings in MW by customer class.

³⁰ <https://www.eia.gov/todayinenergy/detail.php?id=37912> (accessed 1/13/2020).

³¹ <https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf> (accessed 1/13/2020).

the actual demand reduction achieved as a percent of the subscribed (potential) demand reduction reported to the EIA. The SPI relays how well a program is actually achieving DR. Louisiana, with only 0.3 MW of actual and potential DR scores well in DR performance. But other states, for example, Iowa, achieve a high level of performance with much larger amounts of demand reductions, albeit at a higher cost than many states, as shown in Figure 5. Although there is wide dispersion in DR performance, this could be due in part to excess capacity situations across the MISO footprint, which has historically negated the need for DR, except for in emergency situations.

Figure 7: Demand Response Performance



Notes: The Subscribed Performance Index is the total actual peak demand savings divided by the total potential peak demand savings for commercial and industrial customers in each state.

Source: EIA Form 861

4.1.4 Recommendations from the Demand Response Literature

Increasing DR participation in Louisiana will require both understanding Louisiana’s potential for DR and designing DR programs that cost-effectively incentivize participation. The ultimate goal of DR is to reduce demand, and how demand is actually reduced can vary by customer class.

Despite industrial customers comprising the bulk of a utility’s demand,³² and empirical evidence that focusing on industrial customers delivers large DR savings,³³ studies on DR program design, implementation strategies, and performance assessment have tended to focus on residential and commercial customers. Likely because DR program design and implementation for large industrial customers is not a one-size-fits-all approach.

Industrial DR is typically achieved by reducing process demands. Many large industrial processes may need to be individually analyzed for DR potential, often leading to tailored bilateral contracts (Bel et al.,

³² Flory et al. (1994) find that 2%-10% of the industrial customers account for at least 80% of the many utilities’ total electricity demand.

³³ See Barbose et al. (2004), Kiliccote (2010).

2009). But targeting these customers is worthwhile, as Kiliccote (2010) found that industrial customers in California, on average, reduced their peak demand by 14% to 33% between 2006 and 2007.

DR implementation for commercial customers is typically achieved through modifying building services (Kiliccote, 2010). To systematically identify demand response potential in commercial (and some industrial) customers, Bel et al. (2009) recommend a process-oriented market segmentation to identify where energy is used. Commercial and industrial processes like HVAC, lighting, and electronic equipment are flexible segments of demand that are amenable to DR. Demand can be split according to final use: air conditioning, ventilation, electronic equipment, water heating, lighting, etc. By assigning prices to these segments of demand, an economic analysis of the potential benefits and costs of temporarily reducing demand from certain energy-intensive areas can be conducted to determine if demand response will be profitable. When these demand reductions were automated, Kiliccote (2010) found that commercial customers in California reduced peak demand, on average, by 13% between 2006 and 2007.

To achieve DR potential, customers must also be educated on potential demand response strategies for achieving demand reductions. For further reading, Motegi et al. (2007) recommend several strategies for commercial and industrial customers to reduce or temporarily shift energy use in HVAC, lighting, and other industrial processes. Though primarily focused on California, the Berkeley Lab Demand Response Research Center has further industry- and sector-specific strategies for DR implementation.³⁴

A comprehensive examination of how Louisiana's industrial sector customers use electricity, in order to identify what incentive-based DR strategies will work best for Louisiana, is another area for future research.

4.2 Price-Based Demand Response Programs

4.2.1 Program Participation

Price-based demand response is also well-utilized in the MISO footprint. Price-based DR requires demand and supply to be balanced through small demand reductions by thousands of customers, making it harder for grid operators to predict and secure demand reductions, but typically resulting in overall lower average prices (Borenstein et al., 2002). While for grid operators, emergency demand reductions can still be achieved by utilizing incentive-based DR programs as a back-up for price-based programs, ensuring customer responsiveness to price signals remains a challenge (Borenstein et al., 2002).

For a price-based DR program, the objective is to balance the tradeoff between helping customers manage price volatility through advance notice of prices, and having prices accurately reflect real-time electricity costs. With too much advance notice, prices won't reflect actual supply and demand conditions; with not enough advance notice, customers may be subject to volatile electricity prices and electric bills.

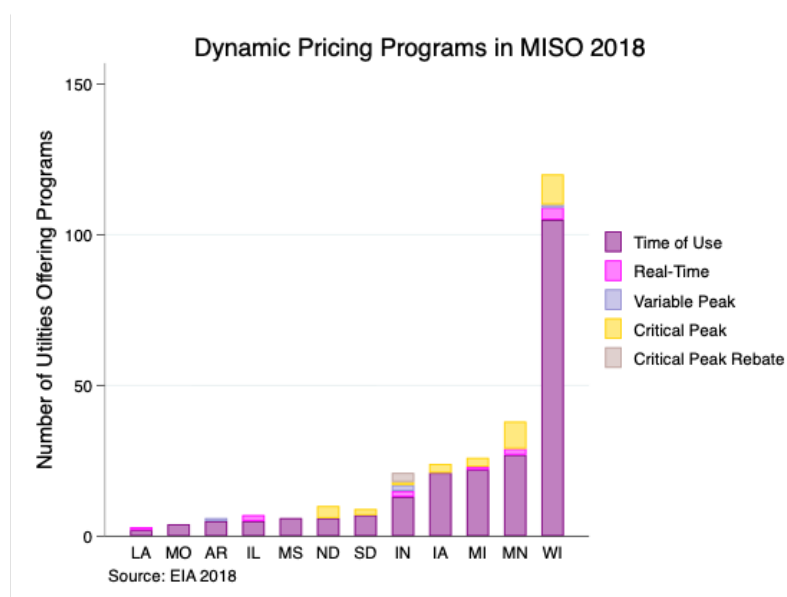
While there is limited availability of commercial and industrial price-based DR programs in Louisiana,

³⁴ <https://drrc.lbl.gov/research-areas/demand-response-resources> (accessed 1/27/2019).

recent deployments of AMI throughout the region should facilitate the advent of price-based DR programs.³⁵ Further, Hurley et al. (2013) propose that AMI-enabled price-responsive demand can be used not only to reduce system costs during peak periods, but also to reduce costs and enhance system efficiency during any hour of the year.³⁶

Throughout MISO, many utilities offer price-based demand response programs to commercial and industrial customers. The number of utilities offering price-based demand response programs across the MISO footprint are shown in Figure 8. Louisiana has a significant opportunity to expand its price-based DR programs offerings, as few utilities currently make dynamic pricing options available to customers. In terms of total commercial and industrial enrollment in price-based DR programs, Louisiana only reported eight customers, as shown in Figure 9.

Figure 8: Price-Based Demand Response Programs in MISO



Notes: Utilities offering dynamic pricing programs by state, within the MISO balancing area, 2018.

Source: EIA Form 861

The Louisiana Public Service Commission’s Proposed Rule (Docket No. R-35136) does not require utilities offer price-based DR programs to commercial and industrial customers; however, with many Louisiana utilities making recent investments in AMI, there is a key opportunity to expand price-based DR in Louisiana. Although TOU rates remain the most common type of price-based programs offered to customers, AMI make many real-time pricing and critical-peak pricing options feasible for customers.

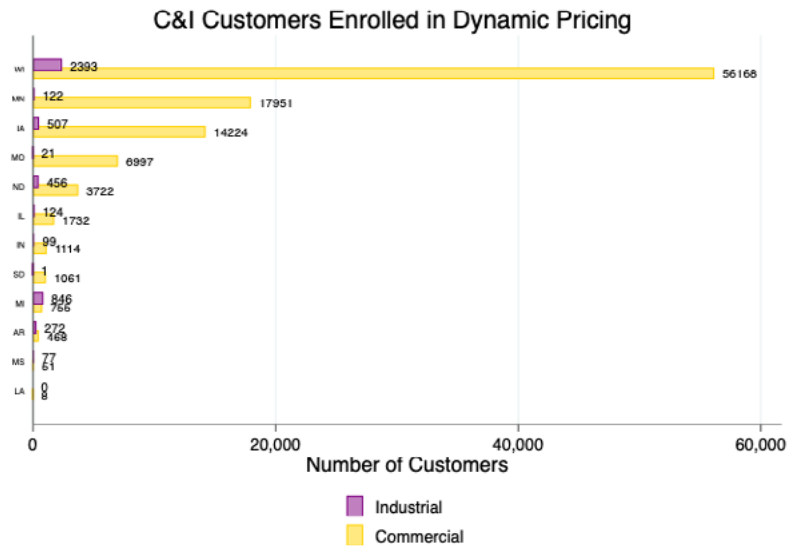
Price-based demand response can be achieved through static or dynamic retail pricing tariffs, or through allowing large commercial and industrial customers to access the wholesale markets directly. Some states, such as Oregon and Georgia, allow retail-price competition for large customers only. In Louisiana, this type of retail-access could be achieved through limited restructuring of the electricity

³⁵ For example, ELL is required to conduct a study regarding the implementation of its demand response programs and incentives and file a report with the LPSC following the deployment of its AMI. See LPSC order no. U34320.

³⁶ Hurley et al. (2013) find that AMI-enabled price-responsive demand can be used to also address periods of excess generation by increasing demand, for example, through the use of space heating.

market, an issue that is currently being considered by the Louisiana Public Service Commission. Further, although the focus of this whitepaper is on increasing participation by large customers in DR programs, AMI can also create opportunities for utilities or third-party aggregators to aggregate demand from residential and small commercial/industrial customers — increasing DR participation.

Figure 9: C&I Price-Based Demand Response Customers



Notes: Commercial and Industrial Customers enrolled in price-based demand response programs within the MISO balancing area, 2018.

Source: EIA Form 861

4.2.2 Recommendations from the Demand Response Literature

To improve price-responsiveness in real-time pricing programs, Barbose et al. (2004) recommend customers receive help on understanding and managing price risk. In reviewing two pilot programs which assessed the effectiveness of time-varying rate programs in achieving DR, Faruqui et al. (2010) found that In-Home Displays, which provided customers with additional information on their electricity usage, augmented the effect of DR. Similarly, for industrial customers, Wang (2015) also found that customers who benefitted most from TOU tariffs not only understood the tariffs, but were able to adjust their production schedules in accordance with the TOU tariffs.

But to achieve DR goals, Barbose et al. (2004) recommend utility incentives be aligned with those goals, through either regulatory directives or performance-based incentives. To that point, Hurley (2013) found that allowing participation of third-party DR aggregators also led to more DR participation, as aggregators face a different set of financial incentives than traditional utilities to enlist and deliver reliable DR from customers, which may increase competition for DR services.

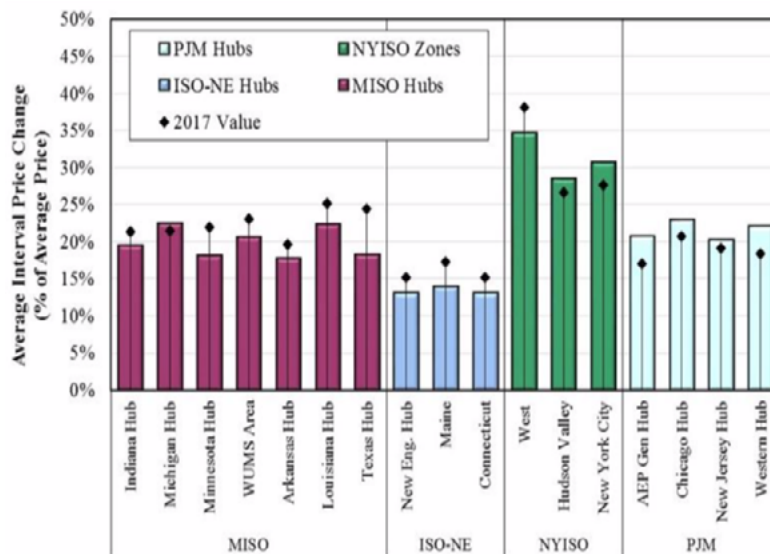
A comprehensive examination of which price-based tariffs have worked best for other utilities, and how these may benefit Louisiana’s industrial sector customers, is another area for future research.

5 Louisiana Demand Response and MISO South

Increasing Louisiana’s participation in demand response programs in the MISO markets is also important for the MISO footprint as a whole. Despite MISO having the largest amount of demand resource participation of any ISO — 9.7% DR as a percent of peak demand in 2017 — there is opportunity for improvement.³⁷ As shown in Figure 10, MISO continues to have volatile prices, with average price spikes in the magnitude of 15 – 20% higher or lower than the average real-time price.

Although MISO outperforms both PJM and NYISO on price-volatility measures, because much of MISO’s real-time price-volatility is due to sharp changes in demand from industrial facilities, increased demand response could also play a part in helping to shape MISO demand to further reduce price-volatility.

Figure 10: ISO/RTO Real-Time Price Volatility



Notes: Shaded bars show the 2018 fifteen-minute real-time price volatility for MISO, ISO-NE, NYISO, and PJM.

Source: Reproduced from MISO 2018 State of the Market Report, at p. 29.

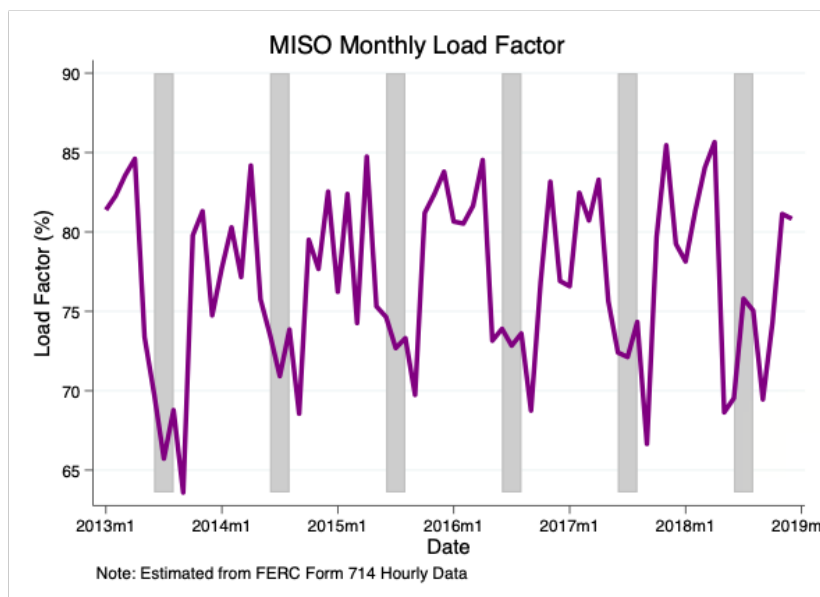
MISO can also improve its demand utilization. A load factor is a measure of utilization based on the average demand divided by the peak demand during a certain time period. Figure 11 shows MISO’s monthly load factor—its average demand divided by its peak demand each month—from 2013 to 2018. In this figure, the purple line shows the load factor, with summer months shaded in grey. It’s clear that MISO’s demand is “peakier” in the summer months. Lower load factors indicate that there is more idle capacity on the system in order to meet occasional demand peaks. Idle capacity imposes higher costs on the system, leading to higher average electricity prices. Because demand response is used to shave-off peak demand, it can improve MISO’s load factor, particularly in the summer months when capacity is underutilized.

The MISO South region, which encompasses Louisiana, also has several “load pockets,” which are areas that are transmission-capacity constrained, often leading to voltage and reliability issues

³⁷ <https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf> (accessed 8/27/2019).

in meeting demand in that particular region. Although MISO has completed several transmission projects to alleviate some of these constraints,³⁸ ELL expects that significant industrial load growth in constrained areas —particularly in the region West of the Atchafalaya Basin and Amite South — will lead to further needs for reliable generation within the load pockets; however, industrial demand response may also be a solution within these regions, as reducing demand during certain times can also help the grid run more reliably and efficiently.

Figure 11: MISO Monthly Load Factor



Notes: Monthly average and peak load is estimated from the FERC Form 714 hourly load data by MISO planning area.

Source: FERC Form 714.

Perhaps one of the most important issues affecting DR participation in MISO is its capacity market design issues that have led to low capacity-market clearing prices. MISO’s independent market monitor has recommended several improvements, including using a sloped rather than vertical demand curve for capacity, transitioning to a seasonal capacity auction, and validating data submitted by participants to certify their ability to perform. Some of these reforms are taking place, and may affect DR participation. MISO recently had new tariff rules approved by FERC to require LMRs to provide their capability for demand reductions for all seasons, rather than just the summer season, to better align with actual emergency events.³⁹ How these reforms will affect overall DR participation is yet to be seen, but further changes to capacity market design may further affect DR participation in MISO.

³⁸ https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf at 38. (accessed 1/20/2020).

³⁹ <https://www.ferc.gov/CalendarFiles/20190219174743-ER19-650-000.pdf?csrt=5829667732512871948> (accessed 2/27/2020).

6 Conclusion

Demand response can be used to shape demand, lower electricity prices and system costs, and run the electricity grid more reliably in transmission-constrained regions. Louisiana, one of the most energy-intensive states in the nation, is uniquely poised to increase DR participation among its large and growing sector of industrial customers. But implementing effective DR programs will require the right balance of increasing DR participation without creating burdensome costs for local utilities and other customer sectors.

Louisiana has several options that it can pursue to increase DR participation, from offering customers access to a variety of utility-administered, incentive-based and price-based DR programs, to increasing customer access to DR programs offered by the MISO market. Determining how to optimally structure Louisiana's DR programs is an ongoing challenge that will require further research. To encourage meaningful DR participation in Louisiana, programs must be properly structured to incentivize participation without being too burdensome on local utilities. Best practices from the literature include establishing accurate customer baselines, providing transparent and reliable compensation mechanisms, and removing barriers to participation.

Although there are tools that Louisiana stakeholders can leverage to increase transparency in determining DR costs and benefits, such as the California Standard Practice Manual, an area for future research is to survey best practices among MISO utilities to determine which DR programs work best and why. From such a survey, standardized methods for calculating customer baselines, and measuring and compensating customer performance, could be developed for Louisiana.

DR is not a one-size-fits-all approach because electricity generation portfolios, customer mixes, and transmission availability vary regionally. Within the MISO footprint, many utilities and states have taken different approaches to incentivize DR participation. With MISO's tightening capacity reserve margins, and increased renewable resource penetration, DR will be called on more frequently in the future.

Two additional areas for future research would be to determine the appropriate capacity value for DR in Louisiana, given current MISO capacity market design issues, and to conduct a comprehensive analysis of how Louisiana industrial sector customers use electricity, in order to identify what DR strategies will work best for Louisiana to achieve meaningful demand reductions, and if they will be cost-effective.

As Louisiana is currently taking important steps to improve DR participation, including instituting requirements for utilities to offer DR programs and deploy AMI to customers, an important next step is to leverage AMI to increase participation in price-based DR programs. Another avenue for future research is to determine which price-based DR programs work best at other utilities, and identify which will work best with Louisiana's unique customer mix, to better guide Louisiana's price-based DR communication and implementation strategies.

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