Used, But How Useful?

How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-Fired Power Plants

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Executive Summary

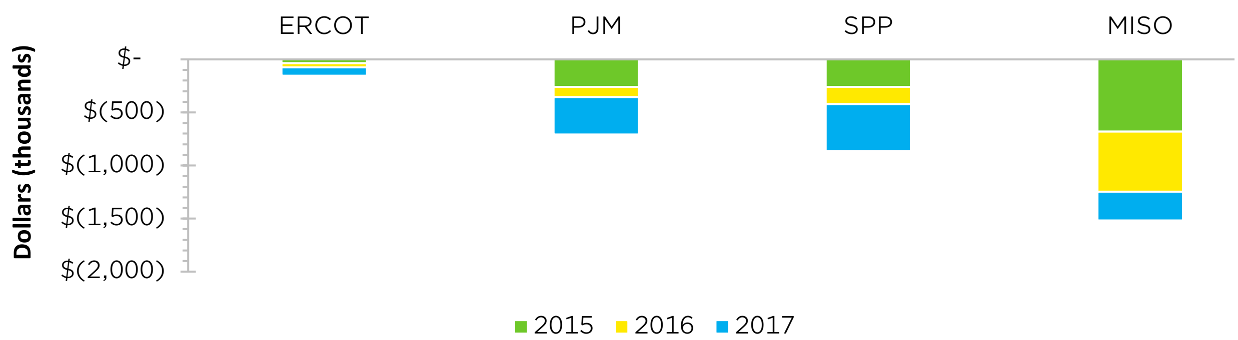
The primary objective of today's wholesale electricity markets, operated by Independent System Operators and Regional Transmission Organization (ISO/RTOs), is to facilitate low-cost, reliable production of electricity. The idea is that market incentives will enforce economically rational behavior from the owners of power plants. ISO/RTO markets were designed for power plants relying on the market for revenue. At the time, it made sense for market rules to allow owners to commit resources however the owners wanted because the desire to maximize profits would motivate each company's decision-making. But today, roughly 50 percent of generation in the ISO/RTO wholesale markets comes from power plants owned by rate-regulated utilities (S&P Global 2020). [1]

ISO/RTO market rules should essentially line up energy resources in merit order (from the lowest cost to the highest cost). However, they include provisions that allow for "self-commitment," a provision that some companies exploit as a loophole allowing resources they own to "cut in line." This loophole would be difficult for independent power providers (IPPs) to profitably exploit because they rely on market prices to cover their costs. But rate-regulated utilities, with rate-based cost recovery, now participate in those same wholesale markets and can exploit the loophole. As a result, such utilities can lose money in daily energy sales but cover their losses in a state fuel-cost-recovery process (Daniel 2017; Daniel 2018; Nelson and Liu 2018; Fisher et al. 2019). The need for resources to be "used and useful," in the language of the industry, may even create an incentive for rate-regulated utilities to over-rely on resources that are objectively uneconomic in the competitive market.

Market rules and economic regulation of monopoly utilities should translate into overlapping oversight of utility operations, but instead they have created this loophole. State regulators may expect that the markets rules and market monitors facilitate the efficient, economic operations of power plants within each ISO/RTO's footprint, but ISO/RTOs have passed the buck back to regulators, who are responsible for adjudicating the prudence of incurred costs.

In 2018, Union of Concerned Scientists (UCS) research suggested that uneconomic self-commitment unnecessarily cost utility customers up to $1 billion a year across four major US power markets—PJM Interconnection (PJM), Midcontinent ISO (MISO), the Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT) (Figure 1). The practice seemed most pronounced in MISO, where the research suggested that utilities uneconomically committing coal plants recovered $250 to $700 million per year at the cost of cleaner and lower-cost resources (Daniel 2018).

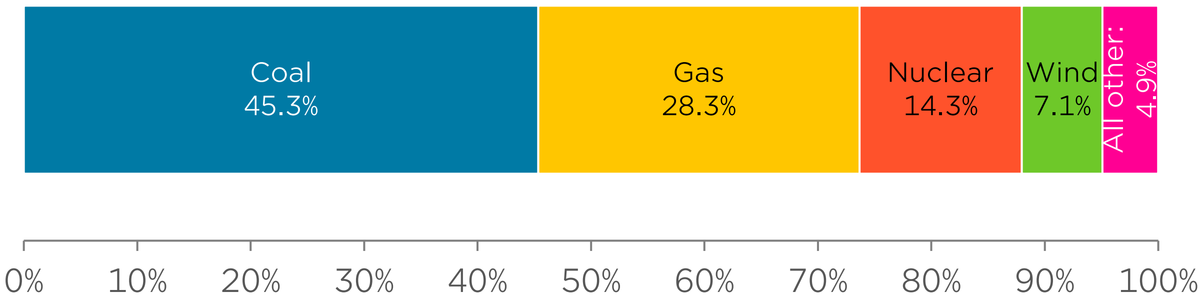
FIGURE 1. Comparative Annual Losses from the Uneconomic Self-Commitment of Coal



Previous UCS research indicated that uneconomic self-commitment of coal was costing customers $1 billion a year across the four coal-heavy ISO/RTOs and was largest in MISO.
SOURCE: UCS, DERIVED FROM DANIEL 2018.

MISO's geographic footprint, one of the largest for grid operators, spans from Minnesota to Louisiana. Its largest source of energy is coal, with 88 percent of coal self-committed into the market (Figure 2) (MISO 2020). Previous analysis indicates that it has the largest amount of uneconomic coal self-committed among the four coal-heavy markets (Daniel 2018; Fisher et al. 2019).

FIGURE 2. MISO Fuel Mix (2018)



In 2018, coal dominated the fuel mix in MISO, which used significant amounts of gas, nuclear, and wind as well.
SOURCE: S&P GLOBAL 2020.

New UCS research, building on the previous work, uses sophisticated software to model the MISO electric grid at high resolution and simulate how the system would meet the electric demands of customers at lowest cost. The modeling yields four key findings:

- While almost all of MISO's coal resources are self-committed, a subset of coal plants and their parent companies drive uneconomic self-commitment and the resulting market distortion.
- Uneconomic self-commitment of coal plants cost customers $350 million across the MISO region in 2018. The cost for the average residential consumer was about $60 for the year.
- Self-committing coal suppresses market clearing prices (and therefore IPP revenue) in all MISO transmission zones. It suppresses market clearing prices in the MISO region at large by $0.63 per MWh or 2.4 percent.
- Curbing MISO's practice of self-committing uneconomic coal plants in the MISO region in 2018 would have increased overall market efficiency and the profitability of power plants across the footprint.

Based on the UCS modeling, customers could have saved roughly $350 million through the more efficient deployment of existing resources in MISO's electric system in 2018. To put that amount in context, MISO reports annually on the system benefits it provides to the region as a centralized market operator. By MISO's own estimate, market dispatch of resources provides roughly $300 million in benefits to customers. This means that MISO could more than double those benefits if all those participating in the market did so more fully.

Across the MISO region, the savings would translate directly into lower electric bills for homes and businesses (Table 1). In some states, residential customers would have saved more than $100 a month in 2018.

TABLE 1. Residential Electric Bill Savings, by State

State	Average Monthly Consumption	Estimated Monthly Residential Savings	Estimated Annual Residential Savings
Louisiana	1,282	$15	$184
Texas	1,176	$14	$168
North Dakota	1,118	$6	$77
Michigan	671	$5	$61
Minnesota	786	$5	$54
Illinois	718	$4	$47
Iowa	893	$4	$44
Arkansas	1,155	$3	$40
Missouri	1,118	$2	$27
Mississippi	1,247	$1	$16
Kentucky	1,166	$1	$12
Indiana	1,006	$1	$10
Wisconsin	692	($0)	($2)

MISO customers would have saved roughly $350 million through the more efficient use of existing resources if its electric system in 2018. For each state, savings reflect only customers within the MISO footprint and are based on UCS modeling and historical consumption patterns of residential customers. Actual savings would depend on the utility service provider, mechanisms for cost recovery, and the profit structure of utility/customer profit sharing.

Higher customer costs result from antiquated practices and paradigms: changed market conditions have made coal-plant operations more expensive than alternative sources of electricity in many hours of each year. Structures for markets, state regulation, and power-plant ownership all contribute to these costs' being passed along to captive customers. However, since the publication of preliminary analyses of these circumstances, several plant owners have announced changes that would take coal plants offline for months at a time. Xcel and Cleco have taken the path of converting units to seasonal operation. Analysis by the utilities themselves align with this report's findings: that consumers stand to save tens of millions of dollars by operating these uneconomic coal plants less often (Ferrell 2018; Morehouse 2020).

Other utilities remain intractable, insisting that they are doing nothing wrong and that analyses like this are chasing ghosts. For example, DTE Electric Co., which UCS identified as the second worst actor, behind only Cleco, insists that its commitment practices do not cost its customers anything (Balaskovitz 2020). This UCS analysis disputes those claims, as do previous analyses by UCS (Daniel 2018) and Bloomberg New Energy Finance (Nelson and Liu 2018), as well as an analysis conducted as part of a fuel-adjustment rate case in front of the Michigan Public Service Commission (Alison 2019).

By exploiting gaps in regulatory oversight and loopholes in wholesale market rules, rate-regulated utilities are cutting ahead in the merit-order line. Rate regulation, coupled with a lack of scrutiny when it comes to cost recovery, has enabled these utilities to lose money in the market without incurring actual losses on their balance sheets. This occurs when a rate-regulated utility submits fuel costs to its state utility commission for fuel-cost recovery and those costs are not compared with market prices to determine if they were indeed prudent. The utility's ownership structure (via rate regulation) allows plant owners to pass through fuel costs in regulatory proceedings.

Lower electric bills could be realized today if only electric companies stopped exploiting loopholes. It is ultimately up to state regulators—on behalf of the public—to ensure that ratepayer risk is managed properly. Markets and federal regulators can assist in the corrective process through reporting and analysis, but just reforming market rules is unlikely to stop the behavior. If a utility is unwilling to respond to current market price signals, changing those prices is unlikely to elicit a response. Regulators are in the best position to stop this practice, either through better-designed incentives associated with cost recovery or by disallowing recovery of imprudent costs.

In most parts of the country, the cost to buy and burn coal exceeds the market price in most hours of the year. From a financial perspective, it makes sense for plants to burn coal for fewer and fewer hours with each passing year. Utilities should not presume that coal plants will continue to operate at high-capacity factors. It is imprudent for them to make default assumptions about how often a coal plant will run through the use of modeling constraints like a must-run designation.

Owners of coal plants that either do not respond or respond only partially to price signals in ISO/RTO markets deprive customers of lower-cost resources and they deprive other generators of revenues. It is doubtful that changes to this practice will materialize if regulated utilities are continually allowed to recover fuel costs, without scrutiny or incentives to improve operations.

Actions, like market rule reform, dedicated investigatory dockets, or even disallowing imprudent costs in a single rate case should not be thought of as a permanent solution. Regulators must remain vigilant. They must apply continued scrutiny and regulatory oversight to this issue, in part because markets evolve. A unit or plant that appears economic today could easily turn uneconomic in these ever-changing times.

For over 100 years rate-regulation of electric utilities has been predicated on the notion that a public regulator can act as a substitute for competition. In a truly competitive market, these levels of uneconomic coal generation would not exist. Where regulators seek to provide discipline in the absence of market forces, a strong signal is needed to bring the utilities' attention to minimize these ongoing expenses. Utilities will throw up strawman excuses for why their coal plants are so uneconomic but it is not incumbent on the regulator to innovate on behalf of the utility. Rather, utility companies are obligated to come up with a solution and regulators should either approve or disapprove of the companies' proposals.

Chapter 1 Introduction

The primary objective of today's wholesale electricity markets, operated by Independent System Operators and Regional Transmission Operators (collectively referred to as ISO/RTOs), is to facilitate the production and transportation of low-cost, reliable power. The idea is that market incentives will enforce economically rational behavior from the owners of power plants, based on the sound theory behind market clearing prices. The desire to maximize profits would motivate each company's decisionmaking process. Indeed, ISO/RTO markets were designed for power plants that relied entirely on the market for revenues, and it made sense for market rules to allow owners to commit resources how the owners wanted.

ISO/RTO market rules should essentially line up energy resources in merit order—from the lowest cost to the highest cost—but they also include provisions for "self-commitment," a provision that some companies exploit as a loophole allowing resources to "cut in line." This loophole is difficult for independent power providers (IPPs) to profitably exploit, but rate-regulated utilities with rate-based cost recovery, which now participate in those same wholesale markets, can exploit it. As a result, rate-regulated utilities can lose money in daily energy sales but cover their losses in a state fuel-cost-recovery process. Rate-regulated utilities may even have incentives to capture an increasing share of costs outside the energy market through rate proceedings and fuel-cost adjustments, a mechanism not available to IPPs (Daniel 2017; Daniel 2018; Nelson and Liu 2018; Fisher et al. 2019).

In 2018, UCS research suggested that uneconomic self-commitment unnecessarily cost customers up to $1 billion that year across four major US power markets—PJM Interconnection (PJM), Midcontinent ISO (MISO), the Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT) (Figure 1). The practice seemed to be most pronounced in MISO, where, the UCS research suggested, utilities dispatching coal plants recovered $250 to $700 million per year at the cost of cleaner and lower-cost resources (Daniel 2018).

MISO's geographic footprint, one of the largest for grid operators, spans from Minnesota to Louisiana. Its largest source of energy is coal, with 88 percent of coal self-committed into the market (MISO 2020). Previous analysis indicates that it has the most amount of uneconomic coal self-committed in any of the four coal-heavy markets (Daniel 2018). *Used, But How Useful* builds on the previous work, using sophisticated software to model the electric grid at high resolution. With a focus on MISO as an example, it also indicates how to replace uneconomic coal generation.

Chapter 2
Background

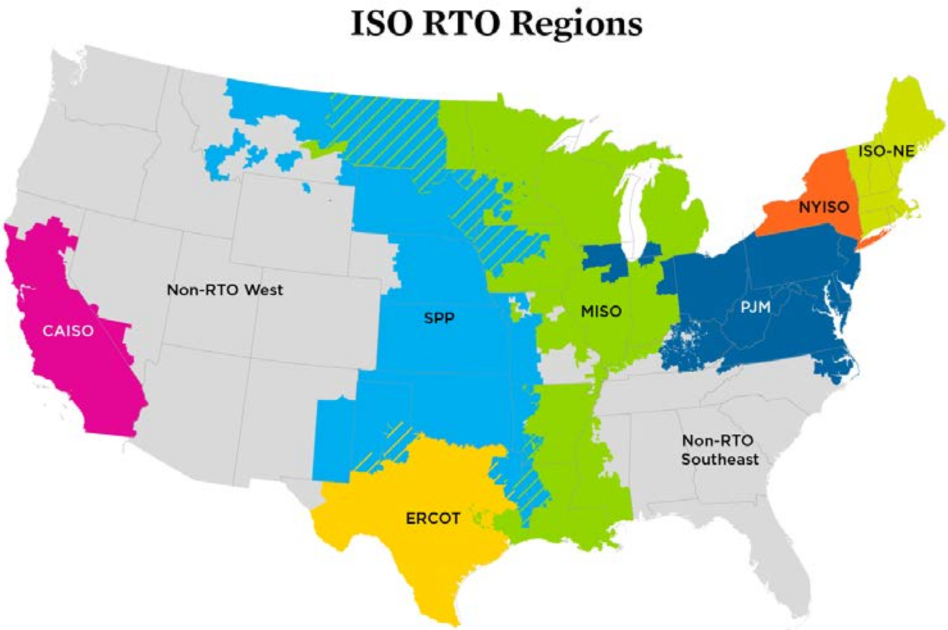
Independent System Operators and Regional Transmission Organizations came into prominence in the United States as a way to give independent power providers access to distribution utilities that directly serve residential, commercial, and industrial customers through an organized, transparent, and competitive framework. [2] Wholesale energy market rules in the ISO/RTOs were designed with the newly independent power providers in mind and assumed that market participants would act in a fashion that would maximize profits for the wholesale market participants, which would also minimize costs to consumers.

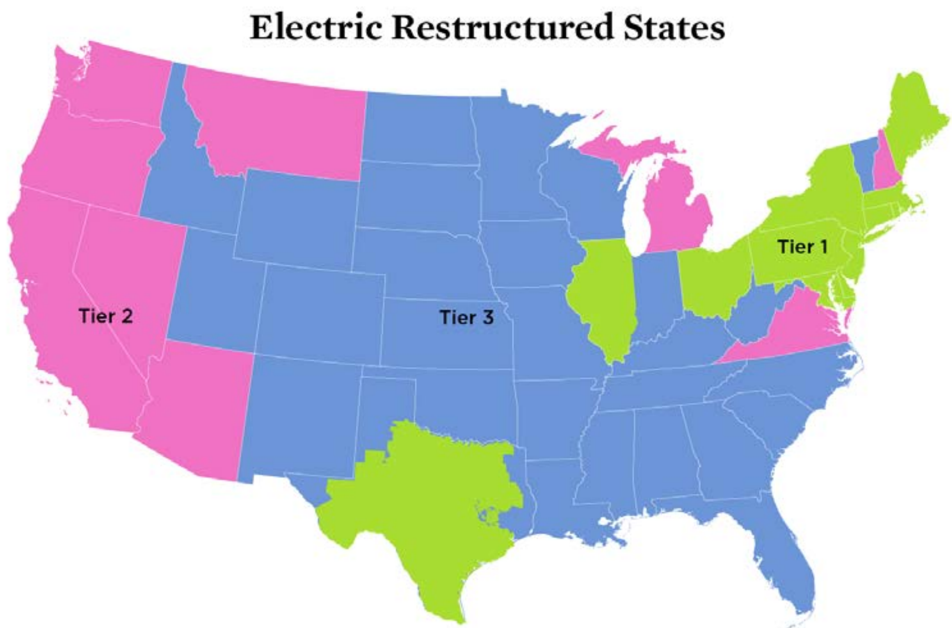
Merchant Versus Monopoly

Generally, two types of ownership of generation assets operate in US electric markets. The *rate-regulated utilities'* ownership of generators, used through most of the 20th century, follows a *monopoly* structure. Toward the end of the century, *merchant power plants* rose in prevalence with the birth of competitive markets and restructuring that forced some monopoly utilities to divest from the generation business. The new owners of merchant power plants came to rely primarily on the market for revenue. After the California Electricity Crisis in 2000 and 2001 and the Enron scandal in 2001, restructuring lost momentum and many states never restructured. Meanwhile, the expansion of ISO/RTO territories continued. The result is that today, many states that have retained rate-regulated structures have utilities that participate in ISO/RTO markets. Today, merchant and rate-regulated power plants operate side-by-side in the wholesale markets administered by the ISO/RTOs (Figure 3). In 2019, roughly 50 percent of generation in the ISO/RTO wholesale markets came from power plants owned by rate-regulated utilities (S&P Global 2020). [3]

Though a rate-regulated utility may generate some revenues from market sales, it does not rely on the wholesale market for revenues. Instead, state regulators approve cost recovery for state-regulated utility generation. In administrative processes like fuel-cost-recovery proceedings, utilities submit receipts for their fuel costs. Before utilities joined ISO/RTOs, there was no transparent market price and source for direct and granular comparison to fuel costs. The practice of showing fuel costs disaggregated from market prices and revenues makes it difficult for regulators to apply oversight or ensure that rate-based power plants operate in a manner that costs ratepayers the least. This has allowed some companies to exploit loopholes in the markets, resulting in unnecessary costs to customers.

FIGURE 3. ISO/RTOs and the Status of Restructuring





The map on the top shows the footprints of each ISO/RTO. The map on the bottom shows the restructuring status of each state. Tier 1 states are fully restructured. Tier 2 states are partially restructured. Tier 3 states have maintained traditional vertically integrated structure. Definitions and designations are set by S&P Global.
SOURCE: S&P GLOBAL 2020.

DIFFERENCE IN OPERATIONAL STYLES

In 2018 and 2019, at least three studies of the US fleet of coal-fired power plants noted stark differences in the operations of monopoly and merchant coal plants. For example, UCS examined every coal unit in PJM, MISO, SPP, and ERCOT, the four coal-heavy RTOs (Daniel 2018). Comparing the operations of merchant and monopoly coal plants within the same market shows that even under the same market rules, ownership structure is the best predictor of behavior. The suite of coal plants that were operating at a loss for long periods of time were predominantly owned by investor-owned utilities (IOUs) and publicly owned utilities (POUs); both have administrative procedures that all but guarantee fuel cost recovery. Independently owned coal plants were generally dispatched in an economically rational fashion (Daniel 2018).

The core UCS findings from 2018 were consistent with an earlier analysis published by Bloomberg New Energy Finance, which found that the majority of coal plants could only stay in operation due to rate-regulation and the ability of the plant owners to recover costs on the back of ratepayers (Nelson and Liu 2018). They were also consistent with a subsequent Sierra Club analysis (Fisher et al. 2019). Both UCS and the Sierra Club monetized the losses of IOUs and POUs, finding that uneconomic generation of coal across the four coal-heavy US power markets was fleecing customers out of $1 billion per year.

For abstracts of these studies, see Appendix A: Summary of Past Reports.

DIFFERENCE IN ECONOMICS

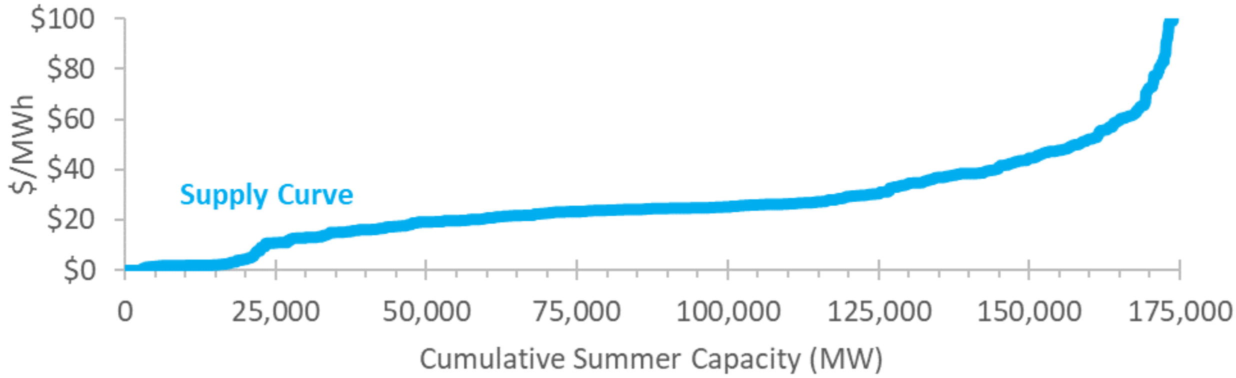
The contrast between the two operational styles is stark and fundmentally a product of the different business models of the two utility types.

Investors in IPPs bear the downside risk of operating at a loss. Consequently, IPPs operate in a way that minimizes losses in the market. For a monopoly utility, however, “losses” in the wholesale market do not translate into losses to its investors. Its financial incentives are not aligned with the rationale behind market rules, and so it is unsurprising that its operations do not necessarily comport to market logic. These utilities pass market losses through to captive customers and recover costs in fuel-adjustment dockets in state regulatory hearings. Regulated cost recovery without active regulatory oversight shifts market risk onto customers instead of the utilities running the power plants.

Market Price Formation Theory

The *theory* behind market price formation is simple and elegant. The ISO/RTO holds a reverse auction. Participants in the market offer a price (in dollars) to provide a quantity of energy (in megawatts) for a given timeframe (example: an hour). [4] At the most basic level, cost offers (in dollars per megawatt) are then lined up in merit order, from lowest to highest cost. This forms the supply curve (Figure 4).

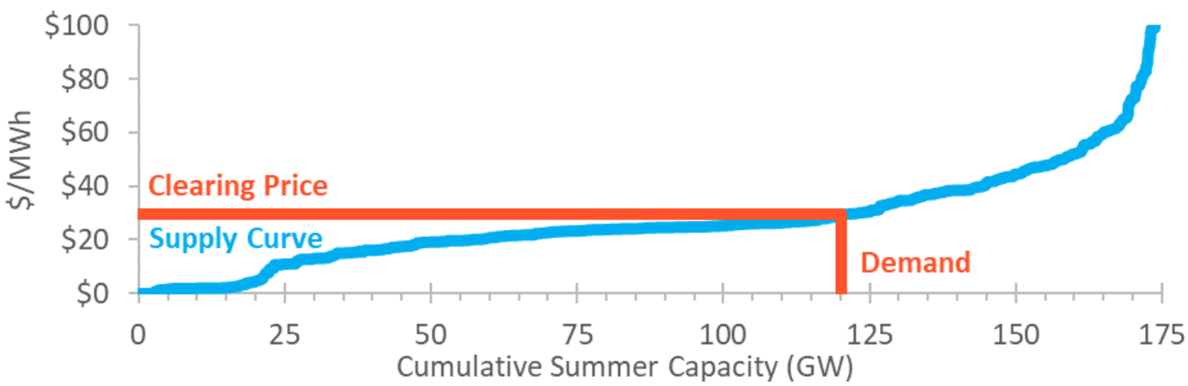
FIGURE 4. Illustrative Supply Curve, based on MISO System (2019)



MISO's 2019 supply curve shows all available resources in the system being lined up from lowest cost to highest cost (merit order).
SOURCE: UCS, DERIVED FROM DATA FROM S&P GLOBAL 2020.

In any given hour, the demand for electricity is a specific amount: the clearing price of the auction is set by the last resource in merit order line that is needed to meet load. All generators that clear the auction receive the clearing price. As a result, the lower-cost generators make a profit and the last generator to clear the market breaks even (Figure 5).

FIGURE 5. Supply Curve, with Corresponding Demand and Clearing Price



A simplified explanation of how the clearing price in the market gets set: The market clearing price in MISO is set by the intersection of supply and demand. All resources get paid the clearing price, which should help incentivize rational bid behavior by existing participants and incentivize inefficient resources to retire and more efficient, lower-cost resource to enter the market.
SOURCE: UCS, DERIVED FROM DATA FROM S&P GLOBAL 2020.

The reverse auction structure is designed to minimize each day's production costs. Those are the costs to operate the entire fleet of generators in a way that reliably meets load. The design should encourage each participant to bid its individual production costs.[5] The rationale is that if a power plant only needs to burn fuel to generate electricity, then it bids those fuel costs into the market. If it clears, it will either break even or make more money than it costs to buy the fuel. The plant owner can use the additional revenues to pay down debt, meet fixed costs, or be counted as profit. If an owner bids below its costs, it may clear the market and receive a clearing price that is below its production costs, thereby losing money in the energy market. If it bids above its costs, it might not clear the market and miss the opportunity to operate during that period and generate revenue (Table 2).

TABLE 2. Game Theory Matrix of Marginal Clearing Price and Offer

Marginal Cost = $30		If the market clearing price is…		
		$26	$31	$36
Offer price	$25	-$4	$1	$6
	$30	Not called	$1	$6
	$35	Not called	Not called	$6

The rational for having a clearing price is simple and sound. If a power plant offers too low a price, it might get called when market clearing prices are too low and lose money. If it bids too high, it will not get called, losing out on the opportunity to make money.

Reality Is More Complex than Theory

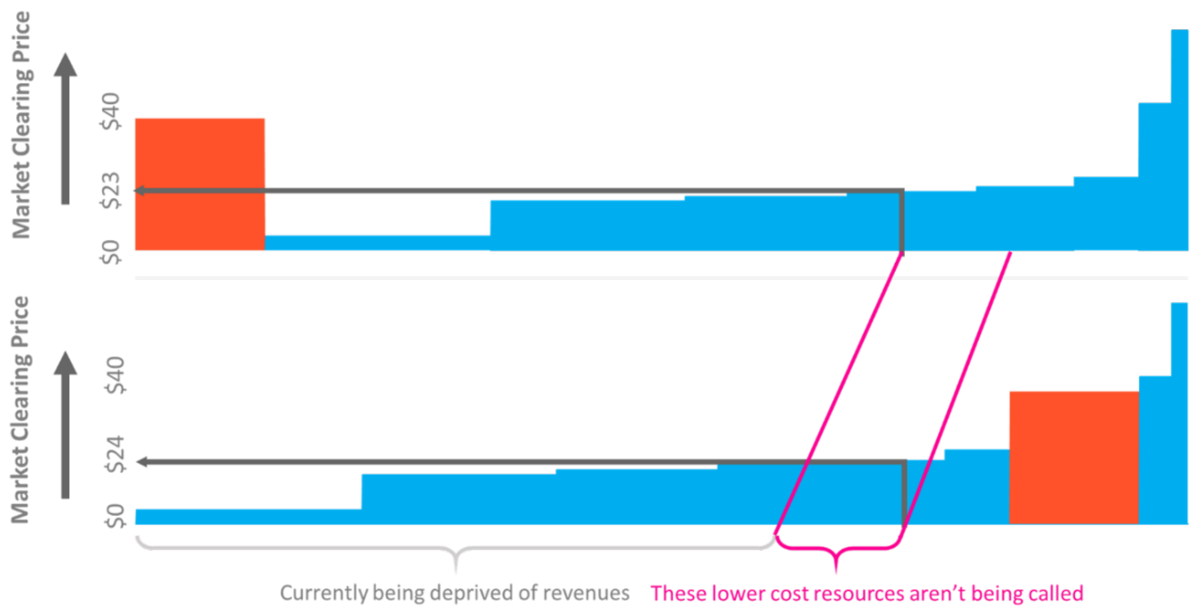
The theory behind wholesale power markets is simple and elegant; its application in the real world is not. Economic constraints (e.g., start-up costs, shut-down costs, fuel contracts) and physical constraints (e.g., minimum up time, minimum down time, ramp rate) exist at some level for all coal generators. While the constraints vary widely, they are often cited in a generalized manner as justification for uneconomic operation in the wholesale markets (MISO 2017a; MISO 2017b; SPP MMU 2019). Because the ISO/RTO markets were designed for power plants that relied entirely on the market for revenue, and because of the sound theory behind market clearing prices, it made sense for market rules to allow owners to offer resources how the owners wanted. Long-run profit maximization would motivate the company’s commitment decisions.

Most markets allow participants to offer/commit a resource in any of five ways:

- *Market/Economic:* The ISO/RTO commits the resource on merit-order basis.
- *Self/Must Run:* The owner commits the resource regardless of price and merit order.
- *Reliability/Emergency:* The resource is only available if there is a reliability need.
- *Outage:* The resource is down for maintenance.
- *Not participating:* The resource is not participating in the market.

The market is supposed to line units up in merit order, from lowest to highest cost. Self-committing effectively allows resources to cut in line (Figure 6).

FIGURE 6. Illustration of How Self-Committing Affects the Merit Order Bid Stack



The orange bar represents a coal plant that is uneconomic but able to self-commit and therefore cut in merit-order line. This pushes lower-cost resources out and prevents their being called by the market to generate, depriving the owners of revenues and potential profit. The practice also suppresses market prices, depriving all generators that did get called of valuable revenues.

For a number of reasons, a utility might self-commit a power plant, but the legitimacy of doing so falls along a spectrum. For example, an air-quality board might require a power plant to test new environmental controls, or a reliability agency might require a plant to test its peak output during the summer. Such testing events are legitimate reasons for self-committing a generator. Typically, they also apply for well-defined and limited periods of time.

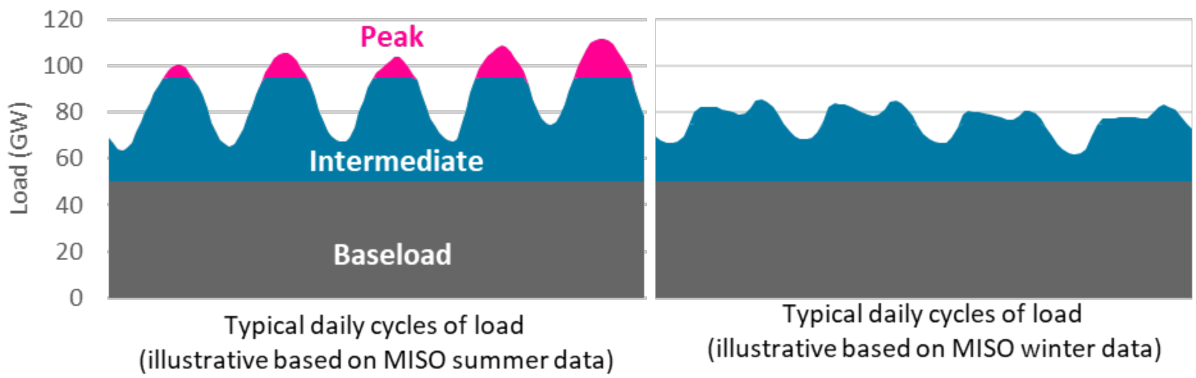
However, the data for all coal plants do not support the assertion that economic constraints or operational limitations alone justify the level of uneconomic operation by monopoly plants observed in past reports and detailed in Appendix B: Summary of Previous Reports

The simplest way to illustrate this point is to observe that merchant coal plants have a much lower level of uneconomic dispatch, despite having to obey all the same physical and economic constraints that monopoly-owned coal plants face (Daniel 2018; Daniel 2019; Fisher et al. 2019; Nelson and Liu 2018). In sum, only in limited instances might physical constraints justify self-committing (even at a market loss) for short periods of time. The physical and economic constraints are insufficient reason for operating months on end at a market loss.

Coal Is No Longer a "Baseload Resource"

The notion that coal is a resource that serves baseload demand (sometimes referred to as a "baseload resource") stems from antiquated paradigms about economic and operational conditions. These paradigms no longer apply to coal plants, as illustrated by the hourly fluctuations of load in MISO on a selection of summer days and winter days (Figure 7). Under the old economic and operational paradigms, baseload resources typically operated at a constant output over the course of the day to serve baseload demand, while mid-merit resources cycled over the course of the day to meet intermediate load; peaking resources turned on or off to meet daily peak demand. In the winter, with less demand on the MISO system, some resources were not needed at all. That dynamic has changed and now a suite of resources acts in concert to serve baseload, intermediate, and peak load.

FIGURE 7. The Traditional, Antiquated View of Load and Power Plants

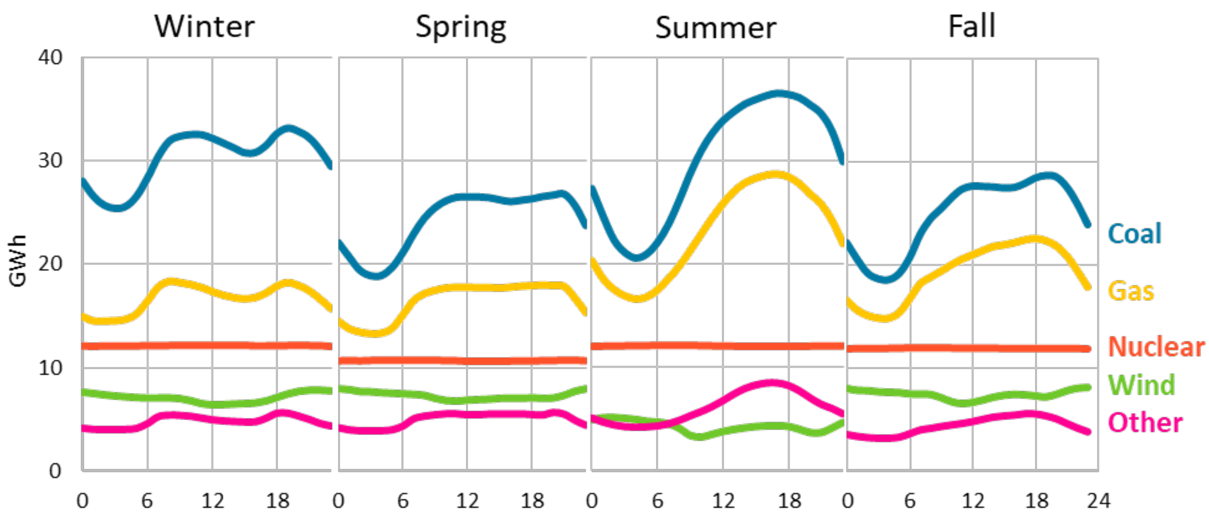


The antiquated way to look at load/generation was to assume that load was inelastic, rather than flexible as it is today. Traditionalists think that baseload is served by a "baseload resource," while peak load is served by "peaker plants." Today, baseload demand can be served by a suite of resources, including renewables. Meanwhile, demand is no longer inflexible. Demand response and flexible demand mean that reliability can be met by increasing generation or shifting demand.
SOURCE: UCS, BASED ON DATA FROM S&P GLOBAL 2020.

This new reality can be seen in the daily patterns of resources in MISO in Figure 7. While coal generation is present all day and all year, at least some of the coal is forced to cycle up and down to follow load patterns to serve intermediate load. Operationally, significant portions of coal capacity in MISO no longer operate as traditional baseload resources.

Economic dispatch is a major driver of the pattern (Figure 8). When generators are market-committed, the ISO will turn units up when economics are favorable and turn them down or even off when the economics no longer justify operating the resources. Self-committing resources can still be turned up or down by the market operator, just not on or off. So, when demand and price go up, self-committed resources can be turned up to follow demand and price. When economic conditions are less favorable, those resources only get turned down even thought it would be more economical to turn them off.

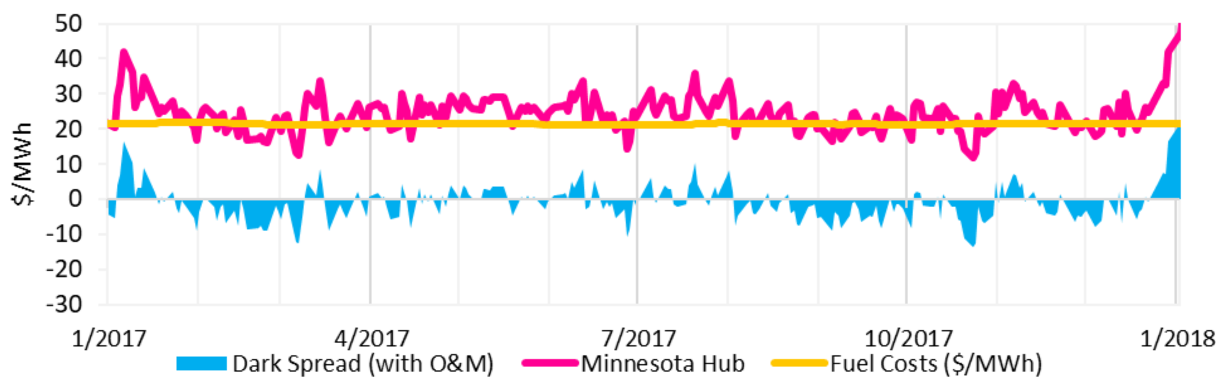
FIGURE 8. MISO Daily Average Hourly Output, by Resource and Season (2018)



While coal generation is present all day and all year, at least some of the coal is forced to cycle up and down to follow load patterns. Operationally, significant portions of coal capacity in MISO no longer operate as traditional baseload resources.
SOURCE: UCS, BASED ON DATA FROM S&P GLOBAL 2020.

One measure of coal's relative economic condition is known as a "dark spread." Dark spread compares coal's fuel and variable costs with the prevailing market price. [6] A positive dark spread indicates favorable economics; a negative dark spread indicates unfavorable economics. The daily dark spread at MISO's Minnesota hub has been negative for the bulk of the coal fleet (Figure 9).

FIGURE 9. Daily Dark Spreads at MISO's Minnesota Hub (2017)



The fuel price is based on the weighted average delivered price of coal to plants in Minnesota. The dark spread is based on fuel plus the variable operation and maintenance costs of a typical coal plant in Minnesota.
SOURCE: UCS, BASED ON DATA FROM S&P GLOBAL 2020.

The historical situation for Minnesota coal is indicative of the realty for coal in much of MISO. In most parts of the country, the cost to buy and burn coal exceeds the market price for most hours of the year. From a financial perspective, it makes sense to burn coal for fewer hours with each passing year.

Profitability of operations can and should be assessed in useful and meaningful periods. A regulatory review need not accept operations that lose money part of the year simply because it is profitable at some other time of the year. If a plant is only economic in the winter and summer, it should run only at those times. Plant costs and various constraints (e.g., start-up costs, minimum run times) can be avoided entirely if the plant does not operate during seasons when it would run at a loss for long periods of time.

Chapter 3
Methodology

Modeling and Research Structure

To assess the potential impact of self-committing coal plants on generator deployment and system operation in MISO, UCS simulated MISO system operations with Energy Exemplar's production cost model PLEXOS. UCS used it in this analysis because MISO itself uses PLEXOS to analyze fleet and bulk grid operations under various economic and policy scenarios.

UCS investigated two scenarios: a reference case approximating MISO operation in 2018 and an economic case. Comparing the results from these scenarios highlights impacts on electricity prices, system cost, dispatch, and consumer electricity bills.

To populate the PLEXOS model, UCS modified the 2018_v1 PLEXOS MISO data package purchased from Energy Exemplar. Based on data from recently published reports, we adjusted Energy Exemplar's dataset with actual prices from 2018 for each individual coal plant.

UCS used PLEXOS to model how existing resources could meet load at least cost in the MISO power system over the course of 2018. The model does not build or invest in new generation or transmission capacity. Unless a generator is designated as "must-run," PLEXOS will choose dispatch from existing resources based on economic and physical constraints (e.g., operating limits, minimum stable factor, must-run, start-up/shutdown, ramp rates), reserve requirements, and transmission limits.

UCS examined several broader financial impacts of self-committing, including the production cost savings for each MISO utility and the net costs of delivered energy for both the MISO transmission zones and the entire region. Production cost is a model output in PLEXOS; the model minimizes the region's production cost while meeting load and observing constraints. PLEXOS defines a unit's production cost using the unit's heat rate, fuel price, start cost, shutdown cost, and variable operations and maintenance cost. The model's calculation includes all these costs in the objective function to minimize system production costs. UCS calculated the difference in production cost between the reference case and the economic case for MISO transmission regions and for individual coal-generating units. We calculated the production cost savings/expenditures by aggregating the difference in production cost between the two cases for each generator, up to the utility level.

Production costs reflect the cost to generate electricity where that electricity is generated. Generation is also transferred into and out of regions to minimize overall regional production cost. Here we define the "cost of delivered energy" as the production costs for a given zone plus the cost of importing (purchasing) electricity from another zone minus the costs associated with generating electricity that is exported (sold) to another zone. We calculated the cost of delivered energy for each zone by adding the production cost to the calculated net import cost for each zone and for the entire MISO region. To find the savings/cost of delivered energy for each transmission zone and the MISO region as a whole, we calculated the difference in the cost of delivered energy between the reference case and the economic case.

SCENARIOS

UCS investigated two scenarios: a reference case approximating MISO operation in 2018 and an economic case. These two scenarios enabled UCS to explore the impact of self-committing coal units on the MISO system. We represented self-committing here by changing the "must-run" generator constraint in PLEXOS. PLEXOS uses this constraint to represent plants with reliability-must-run designations (known in MISO as "System Support

Resources”). Reliability-must-run designations are also used to force plants to operate even when it is uneconomic to do so, mirroring the must-run designation. This constraint is in effect for the entire yearlong analysis period.

THE REFERENCE CASE

The reference case scenario is set up with two goals: replicating plant dispatch in 2018 to calibrate the model and providing a baseline against which to compare the economic case. It approximates actual plant operations in MISO in 2018, using the modified 2018_v1 PLEXOS MISO data package.

To develop the reference case, UCS first ran a scenario with the must-run designation turned off for all coal plants. We compared the coal-generator data from this scenario with historical coal-plant dispatch data from 2018 and generation data from the US Energy Information Administration (EIA). We assigned must-run status to the 121 coal units that fell below historical 2018 generation data. The reference case turned on the must-run designation for these units to approximate historical plant dispatch in 2018.

THE ECONOMIC CASE

The economic case is the result of UCS analysis to approximate what economically optimal plant operations would look like in MISO in 2018. In this case, PLEXOS optimizes generator operation without self-commitment to minimize overall system cost while meeting reliability, reserve, and transmission requirements, contingent on system and operation constraints, including physical limitations of the power plants. The economic case is modeled by removing the must-run classification from all 207 coal units in the MISO region, except for Trenton Channel Unit 9 in Michigan, which has known reliability constraints (MISO 2018).

For more detail on methodology and data sources, see Appendix C: Methodology and Data Sources.

Chapter 4 Results

UCS investigated two scenarios: a reference case approximating MISO operation in 2018 and an economic case. Comparing the results from these scenarios highlights impacts on electricity prices, system cost, dispatch, and consumer electricity bills.

The reference case approximates actual plant operations in MISO in 2018, with "must-run" status assigned to the 121 coal units that fell below historical 2018 generation data. The reference case turned on this designation for these units to approximate historical plant dispatch in 2018. This scenario is set up with two goals: replicating plant dispatch in 2018 to calibrate the model and providing a baseline against which to compare the economic case.

The economic case optimizes generator operation without self-commitment to minimize overall system cost while meeting reliability, reserve, and transmission requirements, contingent on system and operation constraints, including physical limitations of the power plants. The economic case is the result of UCS analysis to approximate what economically optimal plant operations would look like in MISO in 2018.

For detail on methodology and data sources, see Appendix C.

Assessing the Worst Actors

Key Finding: While almost all coal resources in MISO are self-committed, a smaller subset of companies and the coal plants those companies own drive uneconomic self-commitment and the resulting market distortion.

Not all coal in MISO is self-committed uneconomically. UCS prescribed a must-run status to 121 MISO coal units (representing 36 gigawatts) out of the total 207 units (60 GW) that showed lower generation in the economic scenario than in historical data. This indicates how much coal was self-committed uneconomically in MISO in 2018, but it does not indicate how much coal was self-committed in total. According to MISO, nearly all coal capacity in MISO was self-committed (MISO 2017a). Our analysis indicates that 36 out of 60 GW of coal in MISO were committed uneconomically at some point in 2018.

The data from PLEXOS show that many coal plants with a "must run" designation in the reference case cannot recover the power plant's operating costs with energy market revenues alone. Removing the must-run constraints increases a plant's net market revenues by preventing it from running when it is uneconomic to do so. Even for coal plants that could cover annual costs, removing the must-run designation increased net market revenues by preventing them from running on low-price days. Across the 207 coal generators analyzed, the average generator increases market revenues by $1 million. This is higher than MISO's estimate of a $600,000 average increase based on analyzing a smaller cohort of units designated as must-run (MISO 2017a).

The increase in market revenue indicates the burden an individual coal plant places on customer bills by operating uneconomically. Aggregating increases in market revenue to the utility level and displaying plant-level subtotals illustrates that while the average increase for a generator may be $1 million, the increase is much greater for some power plants (Table 3).

By far the largest abuser of the practice in our 2018 modeling was Cleco, co-owner of the Dolet Hills Power Station. Dolet Hills is one of the most expensive coal plants in the country. Historically, it has operated at relatively high capacity considering it was economic in zero hours of the 2018 year. Dolet Hills was the only coal plant that fully turned off in the modeling when the must-run designation was turned off. The UCS modeling showed more than $116 million in customer savings without the must-run designation in 2018.[7] This mostly aligns with the company's own analysis, which indicates that turning off the plant for nine months of the year would save customers $85 million dollars (Ferrell 2018).

The second-worst actor is DTE Energy, serving Detroit and other parts of southeast Michigan. With five coal plants, DTE's uneconomic operations burdened customers with nearly $95 million in unnecessary costs in 2018. The analysis identified DTE as the worst actor behind only Cleco. Moreover, unlike Cleco and the third-worst actor, Xcel, DTE has taken no proactive steps to improve operations at its coal plants. DTE insists that its commitment practices are not costing customers (Balaskovitz 2020). The UCS analysis disputes those claims, as do previous analyses by UCS and Bloomberg New Energy Finance and an analysis conducted as part of a fuel adjustment rate case in front of the Michigan Public Service Commission (Daniel 2018; Nelson and Liu 2018; Alison 2019).

In contrast, Northern States Power Company (doing business as Xcel Energy) has been active in addressing the issue. Pressed by advocates and the state regulatory commission, Xcel Energy has begun exploring options to turn off coal during the months when it does not make economic sense to run its Minnesota-based coal plants. Specifically, Xcel has found that switching the Allen S. King plant and Unit 2 at the Sherco plant to seasonal operations would save customers tens of millions of dollars. The UCS analysis indicates that the utility's customers could benefit even further.

TABLE 3. MISO Coal Plant Owners' Change in Net Market Revenues

Utilities and Power Plants	Gross Benefits	Capacity (MW)	Transmission Zone/State	Number of Residential Accounts
Cleco Power LLC	$123,253,653	1,131	9	244,782
Brame Energy Center (Rodemacher 2)	$7,190,845	493	LA	
Dolet Hills	$116,062,808	638	LA	
DTE Electric Company	$94,741,423	6,256	7	1,992,276
Belle River	$8,503,255	1,270	MI	
Monroe	$18,836,129	3,086	MI	
River Rouge	$1,158,069	280	MI	
St. Clair	$63,431,243	1,100	MI	
Trenton Channel	$2,812,726	520	MI	
Xcel Energy	$56,925,716	2,749	1	1,149,958
Allen S. King	$6,962,270	511	MN	
Sherburne County Plant (Sherco)	$49,963,447	2,238	MN	
Duke Energy Indiana, LLC	$54,039,268	5,072	6	724,302
Cayuga	$11,155,362	1,005	IN	
Edwardsport	$7,479,055	630	IN	
Gibson	$21,853,041	3,157	IN	
R. Gallagher	$13,551,810	280	IN	
Ameren	$43,782,009	5,295	5	1,060,493
Labadie	$21,864,682	2,462	MO	
Meramec	$474,870	619	MO	
Rush Island	$5,579,056	1,222	MO	
Sioux	$15,863,402	992	MO	
Consumers Energy Company	$25,061,878	1,721	7	1,603,125
Dan E Karn	$301,427	258	MI	
J.H. Campbell	$24,760,451	1,463	MI	
Dairyland Power Co-op	$23,905,106	690	1	-
Genoa	$12,822,494	300	WI	
John P Madgett	$11,082,612	390	WI	
NIPSCO	$20,125,538	2,094	6	412,267
Michigan City	$1,665,103	469	IN	
R.M. Schahfer	$18,460,435	1,625	IN	
Wisconsin Power and Light Company	$18,419,492	1,561	2	413,571
Columbia Energy Center	$12,258,346	1,156	WI	
Edgewater	$6,161,146	405	WI	
Wisconsin Electric Power Company	$18,291,623	2,263	2	1,012,377
Elm Road Generating Station	$9,681,172	1,268	WI	
South Oak Creek	$8,610,451	995	WI	

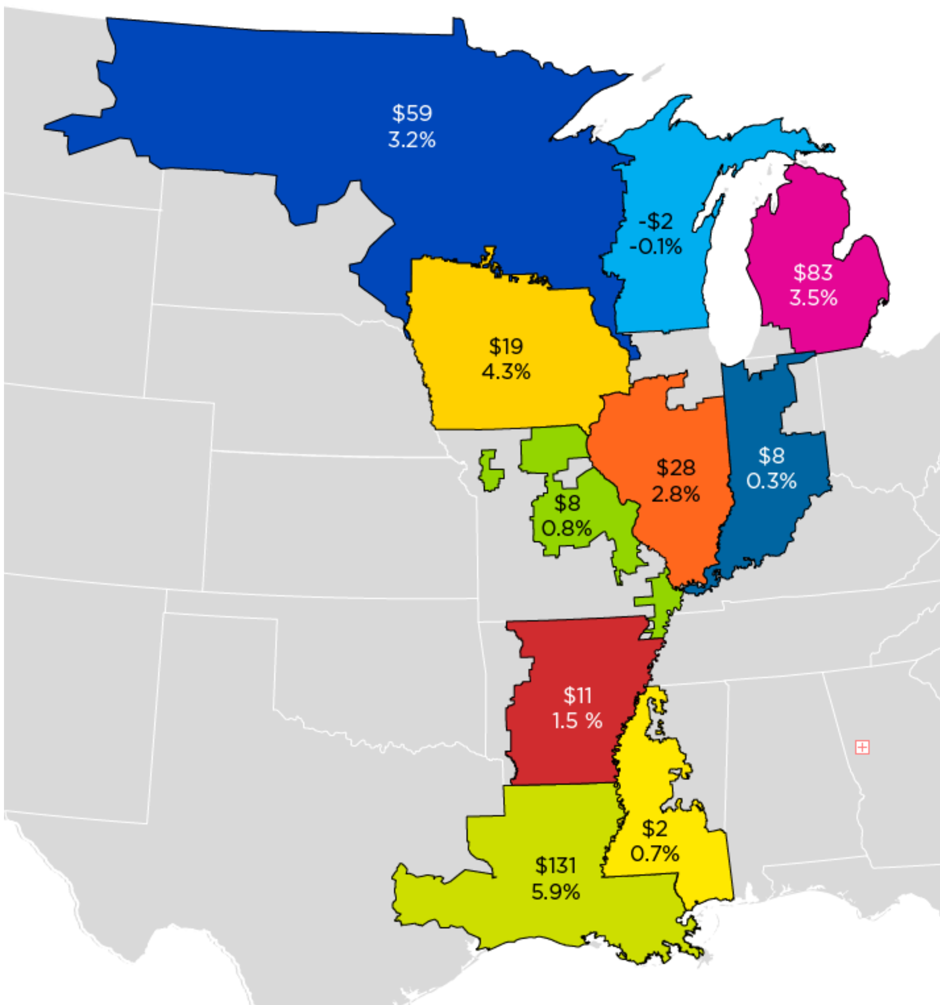
Plants with multiple owners are listed based on primary owner as identified in 2018_v1 PLEXOS MISO data package

Assessing the Impact of Self-Commitment on Consumer Costs

Key Finding: Uneconomic self-commitment of coal plants cost customers $350 million across the MISO region in 2018. For the average residential consumer, that comes to about $60 in higher electric bills for the year.

Present misuse of self-commitment creates costs for customers in the MISO region. If resources where to dispatch economically, the UCS analysis indicates consumer savings ranging from zero to 6 percent as measured by the cost of delivered energy for each zone (Figure 10). Overall savings would be $350 million (2 percent), for the MISO region in 2018 compared with the reference case.

FIGURE 10. Delivered Energy Savings, by MISO Zone



Were resources dispatched economically, consumer savings would be $350 million for the MISO region.
Sources: Map: MISO

Differences in delivered energy savings across MISO transmission zones can be attributed to both the amount of electricity in a zone that was generated uneconomically in 2018 and the cost to replace the uneconomic generation from lower-cost energy sources.

The greatest savings generally appear where the worst actors operated: Xcel Energy in Zone 1, Cleco in Zone 9, and DTE and Consumers Energy in Zone 7. A notable exception is Zone 6, where Duke Indiana, Southern Indiana Gas and Electric, and NIPSCO operate coal plants that incur $90 million in market losses. However, the energy that would replace uneconomic coal generation in Zone 6 is only slightly lower in cost, so customers would realize a $10 million savings instead of the larger savings that would arise if lower costs resources were available. At least in part, this result is an artifact of the static nature of the modeling exercise, which does not include the addition of new, lower-cost resources. Zone 6 saw one of the largest increases in market clearing price; an increase in that price should be an incentive to add more efficient resources.

Savings in delivered costs would reduce costs to ratepayers. Under the economic case, residential electricity bills would go down an average of $5 per month across MISO, or $60 for the year (Table 4). For example, customers in Louisiana are among the most negatively affected by MISO's self-committing uneconomic coal plants. Our analysis found that eliminating the practice would have saved the average residential customer in those states just shy of $170 in 2018. In Michigan, where DTE Energy and Consumers Energy account for the bulk of the state's power supply, residential customers would have saved $61. Customers in Minnesota and North Dakota would have saved more than $50.

TABLE 4. Residential Electric Bill Savings, by State

State	Average Monthly Consumption, MWh	Estimated Monthly Residential Savings	Estimated Annual Residential Savings
Louisiana	1,282	$15	$184
Texas	1,176	$14	$168
North Dakota	1,118	$6	$77
Michigan	671	$5	$61
Minnesota	786	$5	$54
Illinois	718	$4	$47
Iowa	893	$4	$44
Arkansas	1,155	$3	$40
Missouri	1,118	$2	$27
Mississippi	1,247	$1	$16
Kentucky	1,166	$1	$12
Indiana	1,006	$1	$10
Wisconsin	692	($0)	($2)

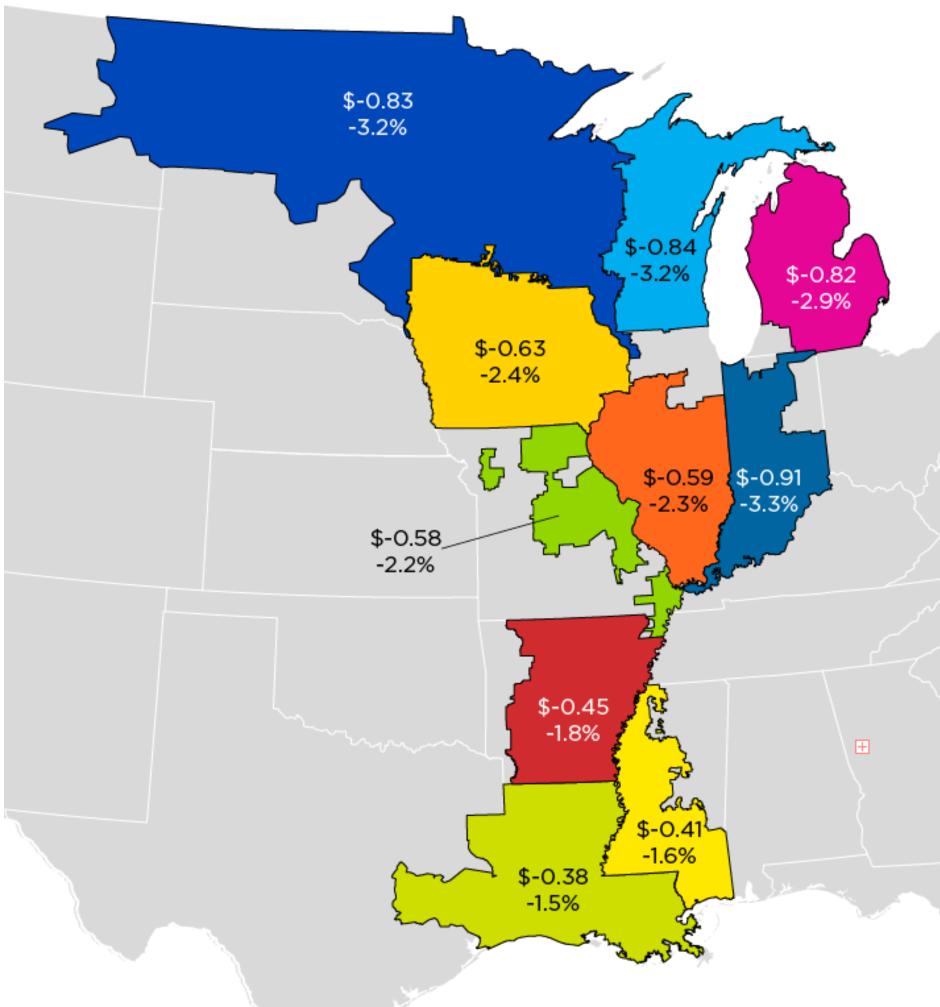
MISO customers in Louisiana and Texas are among the most negatively affected by the practice of self-committing uneconomic coal plants. UCS analysis found that eliminating the practice would have saved the average residential customer in those two states just shy of $170 in 2018. However, only a small portion of Texans are served by a utility that operates within the MISO footprint. Customers in other states would also see significant benefits.

Assessing the Impact of Self-Committing on Market Clearing Prices

Key Finding: Self-committing coal suppresses market clearing prices in all MISO transmission zones; it suppresses market clearing prices in the MISO region at large by $0.63 per MWh or 2.4 percent.

When generators enter the market as must-run, it flattens the supply curve and artificially drives down the clearing price. UCS assessed the clearing price of every transmission zone in MISO and also aggregated results regionally, determining the 2018 difference in clearing prices between the reference and economic case for each of the 10 MISO transmission zones (Figure 11).

FIGURE 11. Price Suppressive Effect of Uneconomic Self-Commitment in MISO



In the UCS analysis, uneconomic self-commitment in MISO decreased the average clearing price across the region by $0.63 per MWh or 2.4 percent

The price suppression is relatively consistent across regions, particularly compared with the potential consumer savings detailed in Figure 11 and Table 4. Clearing prices decrease for all MISO zones, ranging from $0.38 to $0.88 per MWh or 1–3 percent when compared with the economic case. States in MISO North see the largest decreases in clearing price due to self-committing, with the largest decreases in Minnesota, Indiana, and Wisconsin, from $0.83 to $0.88 per MWh, or 3 percent lower. The smallest decreases are in MISO South: a difference of $0.38–$0.45 per MWh, 1–2 percent lower, in Arkansas, Louisiana, and Mississippi. The average clearing price across the region decreases by $0.63 per MWh, 2.4 percent compared with the economic case.

The impact on market prices is a function of two variables: how much coal was uneconomically self-committing and the prices of resources available to replace that coal. This can be thought of as a function of the shape of the supply curve. The supply curve in MISO South is flatter than in MISO North. Another factor is that the largest driver of costs in MISO South is from a single coal plant, Dolet Hills; in MISO North many coal plants (and megawatt-hours) would need to be replaced, making the market-price rebound effect larger. Because of the abundance of lower-cost resources in MISO South, the expensive coal plants could be replaced at a large customer savings and a small corresponding increase in market prices.

Assessing Suppressed Revenues and Market Surplus

Key Finding: Curbing MISO's practice of self-committing uneconomic coal plants in 2018 would have increased overall market efficiency and the profitability of power plants across the footprint. Market surplus of the MISO system would have increased 63 percent.

Suppressed market prices translate into suppressed market revenues for IPPs that rely on the market for revenue. Similar to dark spread, market surplus compares market costs to market revenues. Market surplus is the weighted average spread between costs to generate electricity and energy-market revenue provided for that generation. A positive market surplus is one indicator of a healthy market: it means the market prices are enough to cover the costs of generating electricity (in aggregate). A negative market surplus suggests that the market might not be healthy enough to cover operations costs. High market surplus should be an incentive to add more efficient, lower-cost resources, while low market surplus might result in the financial struggle of existing resources and interfere with efficient entry into and exit from the market.

The increased market surplus that UCS found results from two compounding effects:

- The substitution effect when lower-cost (i.e., more efficient) resources replace more costly coal-fired power plants; and
- The rise in market prices when the clearing price is no longer suppressed by must-run resources.

In the reference case, MISO's market surplus is $1.5 billion. Thus, even though many coal plants incur productions costs that exceed their market revenues by tens of millions of dollars, most power plants could cover the production costs. However, the economic case increases the market surplus by 66 percent to $2.5 billion. This strongly indicates that the market would be healthier when all resources are dispatched economically. This makes intuitive sense, as increased participation in the market is more effective at achieving market benefits and efficiencies.

Chapter 5
Recommendations

Coal plants whose owners either do not respond or only partially respond to price signals in ISO/RTO markets deprive customers of lower-cost resources and other generators of revenues. It is doubtful that changes to this practice will materialize if regulated utilities can continue to recover fuel costs without scrutiny or incentives to improve operations. While only altering how market price signals are formed is unlikely to change the behavior of coal-plant operators, several actions could curb the practice of uneconomically committing coal-plant operations in MISO and other ISO/RTOs throughout the country. Utilities should take actions themselves, while other measures at the state, wholesale market, and federal levels must contribute to the most effective way forward.

Recommendations for Utility Action

Ideally, a utility should take responsibiity for operating as efficiently as possible and ultimately have the power to institute corrective action on its own. Already, some utilities have taken proactive steps to minimize or even eliminate uneconomic self-commitment. Some coal-fired plant operators appear to have done this on their own; many have acted in reaction to pressure from regulators, advocates, the media, and other stakeholders.

ECONOMIC/MARKET COMMITMENT

Utilities have the ability—and arguably an obligation to customers and shareholders—to provide electricity at the lowest cost while markets evolve. It is important to remember that self-committing resources is a choice and that some coal-plant owners choose to offer their plants on an economic basis (i.e., market commit). Regulated utilities provide a litany of reasons to justify self-commitment of coal plants. The simplest, most effective way to resolve this market distortion is for the utilities themselves to market commit their resources for as many hours as possible. Indeed, many operators can and do market commit their coal plants or otherwise avoid uneconomic self-commitment. Others should follow their example.

CYCLING

MISO data indicate that some coal plants are beginning to cycle, ramping output up and down to meet load. This practice can help reduce losses in the market. While cycling a plant may place demands on plant operations, the savings in fuel costs now present in the energy market cannot be ignored. The owners of coal-fired plants should know what costs different levels of cycling impose on their individual generators and use that real information in decisionmaking. Power markets are designed to minimize system costs, and cycling coal plants to perform grid functions, like integrating renewable energy, can save up to $200 in system costs for every $1 in increased unit costs (Lew et al. 2013).

SEASONAL OPERATIONS

In several states, utilities have found that switching coal plants to seasonal operation and running them far less over the course of a year reduces uneconomic dispatch and saves customers money. [8] For example, Luminant's Martin Lake and Monticello coal plants in Texas went to seasonal operations in 2015. The Gibbons Creek coal plant, also in Texas, owned by the Texas Municipal Power Agency and member utilities, followed suit in 2017. Cleco and SWEPCO joined the trend in 2018 when they announced that the Dolet Hills facility in Louisiana would operate only between June and September, months when demand—and electricity prices—are highest. The utilities estimate that change will save customers $85 million by the end of 2020 (Ferrell 2018). Xcel Energy has begun exploring options to go on a "coal holiday" during the months when it no longer makes economic sense to run its Minnesota-based coal plants. Xcel found that switching units at two of its coal plants to seasonal operations will save utility customers tens of millions of dollars (Morehouse 2020).

This trend suggests that customers of two of the worst actors, Cleco and Xcel Energy, might soon realize some savings from reduced reliance on coal through seasonal opperations.

Recommendations for State Regulatory Action

When utilities are unwilling to act on their own, state utility regulatory commissions must step in to protect customers. Preventing regulated monopoly utilities from overcharging ratepayers is a core function of those agencies.

State regulators have numerous mechanisms available to address the issue of uneconomic self-committing and out-of-merit generation. It has thus far been raised in several types of proceeding within state regulatory commissions, including dedicated proceedings, rate cases, fuel-cost-recovery cases, and long-term plans (like integrated resource plans). Each type of proceeding provides a useful but distinct opportunity for regulators to encourage regulated utilities to dispatch their resources in an economically efficient way and, when necessary, penalize imprudent decisions.

For a partial list of these types of proceeding, see Appendix B.

DEDICATED INVESTIGATORY DOCKETS

Regulation of monopolies is supposed to be a substitute for competition. As the differences between how regulated and independent power producers operate coal plants become more obvious, it would be irresponsible for regulators not to investigate the issue of uneconomic commitment practices.

Regulators in Minnesota and Missouri have explored the issue through dedicated investigatory dockets. In both cases, the dockets have been limited in scope, opting for an informal approach, and they have concluded with general courses of action rather than definitive rulings. In Minnesota, the commission ordered utilities to begin filing specific, additional information on uneconomic generation at regular intervals. In Missouri, the commission ordered utilities to file specific information on the practice during fuel-adjustment and cost-recovery dockets.

Some regulators have suggested that proceedings that are less formal, less confrontational enable regulators, intervenors, and utilities to have productive, even collaborative, conversations about issues and potential solutions. This may be true in some cases, but that advantage must be weighed against the need for commissions to be able to compel utilities to provide specific data for the record of regulatory dockets. Less formal proceedings might also lack the consequences needed to stop uneconomic self-commitment of resources.

To strike a balance, dedicated investigatory dockets are a good first step in addressing the issue of uneconomic self-commitment, but they cannot be the final step. Commissions should pursue this option as a way of learning more and determining the best place to litigate and adjudicate solutions.

RATE AND FUEL-ADJUSTMENT/RECOVERY CASES

Utility regulators review the prudency of utility decision-making in a variety of litigated proceedings. For example, in rate cases and fuel-cost-recovery cases, state utility commissions review and determine the reasonableness of costs. Costs must be incurred prudently; assets must be used and useful. If not, associated costs can and should be disallowed.

Operating a power plant when lower-cost resources are available is imprudent. State regulators should carefully examine these cases when brought to them and disallow above-market costs. Such action is well within the jurisdiction of state regulators. Moreover, it is an elegant solution to the extent that it would motivate utilities to operate more in line with rational economic theory.

Disallowance decisions are especially powerful because they create a precedent establishing that a certain action or cost is unacceptable and that the costs associated with that action cannot be recovered on the backs of captive ratepayers. A utility that was disallowed above-market costs would likely explore better ways to operate its coal plants. Moreover, this course of action would have a ripple effect as other utilities under the regulators' jurisdiction would respond accordingly to the new precedent.

This solution helps restore a properly functioning centralized market by forcing monopoly utilities to act more like merchant utilities. Thus, it protects consumers from unnecessary costs, sends the right signal to utilities, and helps drive efficiency in the market, all the while facilitating cost reductions for consumers.

ADDITIONAL SCRUTINY IN UTILITY PLANNING REVIEW

State regulators have the authority, and in some states the obligation, to examine the economics of coal plants when reviewing the prudency of utility investment plans. Such reviews could occur through proceedings around integrated resource plans, or they might fall under the purview of a certificate of public convenience and necessity, a certificate of need, or other similar, forward-looking proceedings. The reviews should scrutinize economic modeling of various resources to project the impact of operating plants on market supply and prices.

Utilities should not presume that coal plants will continue to operate at high-capacity factors. As a general rule, it is imprudent to use modeling constraints like a must-run designation when examining how often a coal plant will run in the future. At the very least, utilities should begin modeling exercises by removing such constraints and then evaluating how often, if at all, coal plants would be needed in the future. From these exercises, utilities and regulators can properly evaluate whether a coal plant should operate year-round using economic dispatch or shut down during long periods of time and operate seasonally.

Regardless, utility regulators should be skeptical of modeling assumptions not presented in a transparent fashion or not available for stakeholder input. Regulators should reject resource plans or requests for approval of any plan in which utility companies force optimization models to keep coal plants operating when lower-cost resources might be available.

Recommendations for Wholesale Market Reform

A 2019 MISO report detailed the "value proposition" that the organized market provides participants. Dispatching the most economic resources to meet the region's electric needs, MISO provided the system with $282 million to $312 million in benefits in 2018 (MISO 2019). Those benefits were realized despite the large portion of capacity not fully participating in the market through the practice of self-committing. Comparing the benefits that MISO currently provides to the potential $350 million in additional production-cost savings the UCS analysis has found suggests that eliminating uneconomic self-commitment would double the benefits to MISO and its customers from energy-market efficiency.

As market operators and analysts grapple with ways to incentivize more participation in the market, they must ask: How will changing price signals affect resources that do not currently respond to price signals? Organizations like MISO have a role to play even though market-level reforms are likely to fail unless paired with strong state regulatory action.

MONITORING AND REPORTING

Market operators and market monitors have access to data that are not available to the public and might not otherwise be available to utility commissions. They also have a detailed understanding of the grid, constraints, and capabilities, coupled with important resources, including modeling software. This gives market operators and market monitors a potentially vital role in reporting and educating the broader community about the topic of self-committing.

As an example, a 2019 report from SPP's Market Monitoring Unit detailed the impact of self-committing and the potential benefits of increased (but not full) market participation. SPP's analysis, which investigated the effects of converting some self-committing plants to market commitments, found that increased market participation could increase market prices by 7 percent and reduce production costs by 0.5 percent (SPP MMU 2019).

MISO has begun to explore ways to address self-commitment issues from the perspective of market participation and system efficiency. Part of that exploration includes a potential multiday market that, coal-plant owners say, would enable them to be more participatory. MISO has analyzed multiday markets assuming different levels of increased market participation (MISO 2017a). When 55 of 230 generators that currently commit as must-run were modeled as dispatched based on economics, MISO found that it could reduce system costs by $55 million; when the number of generators dispatched based on economics goes up to 113, the system benefits by $157 million per year (MISO 2017b). MISO did not indicate which units had the must-run designation removed, but a simple linear extrapolation to the 207 units for which the UCS removed the must-run designation yields a $322 million benefit. This is quite close to the $350 million value found in this UCS analysis.

Studies like the ones conducted by SPP and MISO, when fully participatory and transparent, can benefit both market participants and state regulators. However, it is critical that studies scrutinize utility assertions with skepticism to avoid biased results, with objective evaluations of utility assertions on physical or economic constraints associated with running a coal plant. For example, both the SPP and MISO analyses on the impact of must-run designations suggest that a portion of the coal fleet cannot be market-committed even with multiday lead times, but they fail to ask why those coal plants are the exception. Engineering studies, available to scrutiny, should back up such utility assertions.

MARKET REFORM

MISO and SPP reports have suggested that energy markets need to adopt a multiday forward market to accommodate the constraints of coal plants (e.g., long lead times, high startup costs) (MISO 2017a; SPP MMU 2019). Like the current day-ahead market, a multiday market would likely include a reverse auction for power to meet demand two or three days ahead. Assuming that physical and economic constraints are the source of uneconomic coal generation ignores the fact that many merchant coal plants, operating under the same constraints, participate under current markets in a way that is economically rational (Daniel 2018; Nelson and Liu 2018; Fisher et al. 2019).

Monopoly utility companies are more responsive to cost-recovery incentives than to wholesale market price signals. Altering how those market price signals are formed is unlikely to change their behavior. Moreover, some utilities that self-commit have claimed to do so because operators look ahead seven to 14 days to determine if a unit will turn on or shut off. If utilities use a multiday forecast longer than three days to make decisions and the market only expands to three days, the expanded timeframe is unlikely to affect decisionmaking.

If market operators do pursue multiday markets or other reforms, they should couple those reforms with restrictions on self-commitment. These should be followed up with strong evaluations of and reporting on the efficacy of reforms to reduce uneconomic self-commitment.

While market reforms alone will not solve the issue of self-committing, they can act in concert with state regulatory reform that forces monopoly utilities to participate in the market rationally and respond to price signals.

Recommendations for Federal Energy Regulatory Commission Action

In November 2019, FERC Commissioner Richard Glick stated that self-committing "is fundamentally a state's issue."[9] But while state commissions must be proactive in exercising their regulatory oversight responsibility, the Federal Energy Regulatory Commission could assist in several ways.

First, FERC could help inform and educate state commissions, market participants, and other stakeholders about the troubling issue of out-of-merit generation. This might include updating the analysis conducted in FERC's 2007 study on economic dispatch, hosting technical hearings, and requiring utilities to report out-of-merit generation of resources.[10]

Another important role that FERC can play is by reacting to ISO/RTO proposals to reform market rules. FERC is ultimately responsible for approving such proposals. Were an ISO/RTO to move forward with a change to its tariff as a means of addressing out-of-merit generation or participation in economic dispatch, FERC should evaluate whether the proposal would reasonably be expected to reduce out-of-merit generation, increase market participation, and have potential for unintended consequences.

Chapter 6
Conclusion

The modeling presented in this report confirms that uneconomic generation of coal could be replaced by other, existing resources that are lower cost. Based on the analysis presented in this report, MISO is currently achieving less than half of the $650 million in energy market benefits it could be providing if only more participants in the market truly participated in the market. And those inefficiencies are costing customers every month on their electric bills, about $60 a year for an average residential customer in MISO.

State regulators expect that markets rules and market monitors facilitate the efficient, economic operations of power plants within the ISO/RTO footprint. Meanwhile, markets have passed the buck back onto regulators, insisting that they are responsible for adjudicating the prudence of incurred costs. Although market rules and economic regulation should create overlapping oversight over regulated utility coal operation, some regulated companies have exploited a major loophole, incurring unjustifiable fuel costs that they force onto customers through cost-recovery dockets at the state level.

State regulators must step in to stop this practice. Without strong regulatory oversight with corrective incentives or disincentives, consumers will continue to lack protection from utilities that take advantage of loopholes and fail to operate their plants economically.

ISO/RTOs and FERC can assist in the corrective process through better reporting and analysis, but reforming market rules is unlikely to stop the behavior on its own. If a utility is unwilling to respond to current market price signals, changing those prices is unlikely to elicit a response because market prices are not driving the behavior. Accordingly, the first step in addressing self-committing must be to disincentivize the automatic cost recovery of fuel that shifts the risk and burden onto customers. Other actions, like market rule reform, dedicated investigatory dockets, or even disallowing imprudent costs in a single rate case are helpful even if they are not permanent solutions. Regulators must remain vigilant and apply continued scrutiny and regulatory oversight, in part because the markets continue to evolve. A unit or plant that appears economic today could easily turn uneconomic in these ever-changing times.

For over 100 years, our nation has predicated rate regulation of electric utilities on the notion that a public regulator can act as a substitute for competition. In a truly competitive market, however, today's levels of uneconomic coal generation would not exist. Where regulators seek to provide discipline in the absence of market forces, only a strong signal will move the utilities to minimize these ongoing expenses. Utilities will throw up phony excuses for why their coal plants are so uneconomic, but it is not incumbent on regulators to innovate on their behalf. Rather, utility companies must come up with solutions, and regulators should approve or disapprove of the companies' proposals.

Appendix A
Summary of Previous Reports

Several studies have found that rate-regulated utilities can lose money in daily energy sales but cover their losses in a state fuel-cost-recovery process.

Daniel, Joe. 2017. Backdoor Subsidies for Coal in the Southwest Power Pool. Washington, DC: Sierra Club. https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf
This analysis focused on the frequency of self-committing coal plants in the Southwest Power Pool (SPP) in 2016. According to SPP Integrated Market Data, nearly half (48 percent) of the energy generated in SPP in 2016 came from coal. Moreover, nearly all of the energy generated by coal (43 percent of the total energy generated in SPP in 2016) resulted from self-committing practices rather than in response to market price signals. A screening test compared the actual capacity factors of the nearly 1,700 electric generating units in SPP to an "ideal" or expected capacity factors. The analysis flagged 20 coal-fired units that seemed to operate at least 30 percent more than would be expected given operating costs and typical loads. To quantify the economic impact of self-committing by the flagged coal-fired units, and to account for spatiotemporal variations in market conditions in the SPP territory, a high-resolution analysis used hourly generation, costs, and revenue data submitted either by utilities or the SPP market and compiled by S&P Global Market Intelligence. This hourly analysis, conducted for 14 of 20 flagged coal-fired units for which hourly data were available, determined that nine of the 14 coal-fired units could not recover production costs over the two-year period. All 14 operated at a loss on a monthly basis for six to nine consecutive months during the analysis period. Captive customers incurred an estimated cost of nearly $300 million due to uneconomic operations during the two-year period.

The Power Bureau. 2017. Analysis of Market Impact for Proposed EmberClear Generation Facility in Pawnee Illinois. Chesterton, IN. http://files.sj-r.com/media/news/Chamber_Report_on_EmberClear.CWLP.pdf.
This analysis of the effects of a natural-gas-fired, combined-cycle power plant proposed by the EmberClear Corporation in Pawnee, Illinois, on regional wholesale energy prices uncovered uneconomic coal generation by City Water Light and Power (CWLP), the local municipal utility. The Power Bureau ran two simulations of the 2022 wholesale electricity market in the MISO CWLP region, one with and one without the gas plant, to determine the effect on wholesale energy prices. The market simulations utilized a transmission-constrained, chronological-dispatch algorithm to estimate hourly electricity prices. They utilized publicly available data from multiple sources (NERC, EIA, EPA, and others) to inform various assumptions about load, fuel prices, transmission capacity, and generation-asset availability. The Power Bureau then analyzed the CWLP operations and financial reporting for 2016 to see how potential changes in wholesale energy prices would impact CWLP: none of the CWLP fleet would have marginal costs below the projected day-ahead market clearing prices at any point in 2022. Furthermore, CWLP's current average 2016 market bids were insufficient to cover all of its variable costs. Rather, the average full cost of operating CWLP's generation sources in 2016 (including costs of fuel, operational O&M, and debt) was $76.98 per MWh, which on average was $50.22 per MWh above the wholesale market price and cost ratepayers about $82.8 million in 2016 alone.

Nelson, William, and Sophia Liu. 2018. Half of U.S. Coal Fleet on Shaky Economic Footing. New York, NY: Bloomberg New Energy Finance. https://www.bloomberg.com/news/articles/2018-03-26/half-of-all-u-s-coal-plants-would-lose-money-without-regulation.
This analysis evaluated US coal fleet operations between 2012 and 2017, nationally and regionally, utilizing the Bloomberg Terminal API to assemble pricing and performance data for US power plants. Most of the analysis was

based on estimates of revenues and costs of coal-fired units, which were derived using hourly power pricing and data found on the Bloomberg Terminal (compiled from various reporting sources such as the EIA, EPA, and the ISO/RTOs). The authors estimated that about 48 percent of the coal fleet (135 of 280 GW) posted negative margins for the period studied. Most of the coal plants that posted negative margins (130 of 135 GW) were in rate-regulated utilities; uneconomic coal-fired plants owned by merchant power producers tended to respond to negative margins more quickly. Many of the worst offenders were geographically concentrated in the non-RTO Southeastern United States and Florida, areas that tend to have high fuel transportation costs and low reserve margins in local energy markets. The report concluded that continual declines in energy margins would likely leave merchant coal plants vulnerable, as they cannot make up losses through capacity market payments or rate cases. Furthermore, coal plants in rate-regulated markets with high-capacity reserve margins or whose operational losses exceeded the net cost of new power sources (CONE—cost of new entry) would also be vulnerable to retirement.

Daniel, Joe. 2018. "Out-of-Merit Generation of Regulated Coal Plants in Organized Energy Markets." Washington, DC: United States Association for Energy Economics. https://s3.amazonaws.com/ucs-documents/clean-energy/Daniel-2018-USAEE-Abstract.pdf.
This compared merchant and rate-regulated, coal-fired power plants participating in four centralized energy markets (PJM, MISO, ERCOT, and SPP) from 2015 to 2017, asking whether coal plants were operating economically. The idealized and actual capacity factors of each plant in the four RTOs were calculated, using reported generation output, estimated unit production costs, and energy-market prices at corresponding energy nodes. The results indicated that merchant owners were more likely than rate-regulated owners to decommit coal plants in response to decreases in market prices. Furthermore, rate-regulated plants were more likely to continue operating in low-cost hours and therefore more likely to generate at a loss, presumably because rate-regulated owners could recover losses (albeit at the expense of captive customers) through rate proceedings. Resulting market losses from coal operations exceeded $4.6 billion over the three-year study period when measured monthly, with nearly 70 percent of the losses ($3.2 billion) incurred by rate-regulated, coal-fired plants. Of the $3.2 billion in losses, MISO customers accounted for the largest cumulative gross market losses ($1.5 billion), followed by SPP customers ($900 million). For PJM customers, the losses were $700 million. ERCOT customers lost $154 million; their customer costs came from municipal- and cooperative-owned units rather than merchant units. The remaining market losses came from PJM, with an additional $1.4 billion in market losses incurred by merchant regulators on top of losses incurred by captive customers.

Fisher, Jeremy, Al Armendariz, Matthew Miller, Brendan Pierpont, Casey Roberts, Josh Smith, and Greg Wannier. 2019. Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets. Oakland, CA: Sierra Club. https://www.sierraclub.org/sites/www.sierraclub.org/files/Other Peoples Money Non-Economic Dispatch Paper Oct 2019.pdf.
This analysis quantified the impact of coal plants dispatching out-of-merit from 2014 to 2017 in MISO, SPP, ERCOT, and PJM. Comparing actual capacity factors with idealized capacity factors indicated that most of the coal-burning units operating more than market conditions would suggest were rate-regulated plants. This pattern could be seen broadly across MISO, SPP, and ERCOT. MISO was the biggest offender, accounting for the largest number of non-economically dispatched coal-fired plants of the four RTOs studied. PJM seemed to be the exception: most coal plants in PJM followed market behavior rather closely. Overall, coal plants with net-negative revenue lost an estimated $3.8 billion from 2015 to 2017; plants owned by rate-regulated utilities incurred 79 to 87 percent of the losses. This translated into an estimated cost of $3.5 billion to ratepayers of regulated utilities. The authors worked with Synapse Energy Economics to study the MISO market further, using a unit-specific, chronological dispatch model (EnCompass) with transmission and operational restraints to model the baseline (actual) conditions in the 2017 MISO market and the optimal dispatch in the same year. The modeling indicated that economic dispatch of MISO's coal plants in 2017 was both feasible and would have resulted in about 10 percent less generation by coal plants, primarily by those owned by rate-regulated utilities. Furthermore, economic

dispatch would have lowered the total production costs of coal plants in MISO by $1.29 billion and decreased systemwide production costs by a projected $682 million.

Southwest Power Pool Market Monitoring Unit. 2019. Self-committing in SPP Markets: Overview, Impacts, and Recommendations. https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.
An empirical analysis indicated that the volume of self-committed megawatts (of all fuel types) decreased in SPP between March 2014 and August 2019 but still represented nearly half of the energy generated in SPP. Energy generation from coal self-commitments dominated over other self-committed fuels by a factor of more than four to one. Furthermore, energy generated from coal self-commitments nearly equaled the total energy generated from all market-committed units throughout this period and even exceeded market-committed generation in 2015 and 2016. The modeling portion of the analysis explored the effects of eliminating self-committed resources by re-solving the SPP day-ahead market. This was done for one week of each month for one year for each simulation. The three simulations were business-as-usual, transitioning the self-committing plants to market status, and transitioning the status of self-committing plants while also specifying longer lead times. The report concluded that transitioning self-committing plants to market commitments alone could increase marginal prices by an estimated 20 percent, or $6 per MWh. It could also increase total production costs by 8 percent. However, transitioning self-committing plants to market commitments while also creating a longer market window would increase marginal prices by 7 percent but instead decrease total production costs by an estimated 0.5 percent; this could be one way to discourage self-committing.

Appendix B
Partial Listing of State Dockets

The issue of uneconomic self-committing and out-of-merit generation has been raised in several types of proceeding within state regulatory commissions, including dedicated proceedings, rate cases, fuel-cost-recovery cases, and long-term plans (like integrated resource plans).

Dedicated Investigatory Dockets

Missouri: PSC Docket No. EW-2019- 0370
Minnesota: PSC Docket Nos. E-999/AA-17-492, E-999/ AA-18-373

General Rate Case or Fuel Rider Cases

Arkansas: APSC Docket No. 190008-U
California: CA PUC Application 19-08-002
Iowa: IUB Docket No. RPU-2019-0001
Iowa: IUB Docket No. RPU-2018-0003
Indiana: URC Case No. 45253
Indiana: URC Case No. 38707–FAC123
Kansas: KCC Docket No. 18-WSEE-328-RTS
Louisiana: PSC Docket U-34794
Michigan: PSC Case No. U-20069
Minnesota: PSC Docket No. 19-704
Missouri: PSC Docket No. EW-2019- 0370
Missouri: PSC Docket No. ER-2019-0335
New Mexico: PRC Case No. 19-00170-UT
Texas: SOAH Docket No. 473-17-1764/PUC Docket No. 46449
Wisconsin: PSC Docket No. 5-UR-109
Wisconsin: PSC Docket No. 6690-UR-126

Integrated Resource Plans

Michigan: PSC Case No. U-20471
North Carolina: Docket No. E-100 Sub 157

Appendix C
Methodology and Data Sources

This appendix describes UCS's methodology and assumptions for developing the analysis in this report.

Plexos Model Software

UCS used Energy Exemplar's PLEXOS model to analyze the effects of self-committing coal plants on generator deployment and system operation in MISO. PLEXOS is a production cost model used by transmission planners, market analysts, system operators, investors, regulators, and consultants worldwide. Production cost models simulate the operation of specified power systems over a specified time period, integrating generation dispatch, transmission power flow, and ancillary services dispatch.

PLEXOS optimizes the operations of generators in an electric system to minimize overall production cost while observing the impact of various constraints such as generator operating conditions (e.g., operating limits, must-run, start-up/shutdown costs, and ramp rates), reserve requirements, and transmission limits. PLEXOS optimizes system operations at high temporal and spatial resolution. PLEXOS calculates the least-cost dispatch of systems, like MISO, of interconnected generators to reliably meet load every hour of the day in a region. PLEXOS provides a detailed representation of individual generators and transmission systems. It specifically addresses such issues as transmission, reliability, and seasonal load and generation variability.

UCS used PLEXOS because MISO itself uses it to analyze fleet and bulk grid operations under various economic and policy scenarios. To populate the PLEXOS model, we modified the 2018_v1 PLEXOS MISO data package purchased from Energy Exemplar, adjusting the dataset on individual coal plants and coal prices based on data from recently published reports.

Modeling Limitations and Uncertainties

The intent of the modeling was to consider the practice of self-committing and better understand the practice's implications around generator dispatch and system cost. We make no claim that the historical and counter-factual scenarios perfectly predicted the future; rather, the modeling scenarios provided self-consistent frameworks to assess the effects of the practice of self-committing on system operation. The goal was to illustrate the potential impacts of the scenarios to build on analyses conducted by other organizations using models and assumptions developed by credible, independent sources and informed by real-world data. The value of this analysis lay more in the difference between scenarios rather than the absolute values of each scenario itself.

Overall PLEXOS Model Assumptions

UCS made some changes to Energy Exemplar's MISO dataset. The 2018_v1 PLEXOS MISO data package for PLEXOS used data from EIA reports (EIA-86 and AEO), data from S&P Global Market Intelligence, historical market information, and nodal-power-flow analysis. For generators in MISO, generator capacities were from EIA 860 reports. Generator heat rates were from EPA CEMS data. Fixed and variable O&M were from EPA AEO Base Case v.5.13, broken up by installed emission controls and age of the plant. Forced outage and maintenance rates were derived from EIA, NERC, and ISO reported data. For load data, we used historical hourly load data by transmission zone from MISO. Natural gas prices came from New York Mercantile Exchange (NYMEX) prices for 2018. UCS based changes to Energy Exemplar's MISO dataset to reflect historical operations in the MISO system. The changes included modifying fuel-cost data for coal plants and coal-plant retirements and conversions:

- *Fuel Cost:* UCS changed Energy Exemplar's dataset on fuel cost for coal plants. The 2018_v1 PLEXOS MISO data package used national coal prices from the AEO 2019, which we replaced with plant-specific coal prices obtained from the Fuels Receipts data in the EIA form-923. We based plant-specific revisions on the weighted-average delivered price of coal in 2018. For generators that did not report price data in EIA form-923, our analysis reflected S&P Global fuel prices at the plant level.
- *Coal-Plant Retirement and Conversions:* The 2018_v1 PLEXOS MISO data package used coal retirement data from EIA form-960. There was data lag due to delays in the reporting and publication process. Over the course of 2018, 2.4 GW of coal were retired from the MISO system, and several units were converted from coal to burning other fuels, mainly natural gas. The Sierra Club keeps meticulous track of coal-plant retirements and manages a repository of all coal-plant retirements and announcements. UCS used that dataset for coal-plant retirements and conversions as of September 2019 (Table 10).

TABLE 10. Coal Retirement Adjustments

Power Plant (Unit)	State	Retirement Date/Plant Conversion
Bailly (7)	Indiana	5/1/2018
Bailly (8)	Indiana	5/1/2018
Baldwin Energy Complex (3)	Illinois	Mothballed
Eckert Station (1)	Michigan	Retired before 2018
Eckert Station (3)	Michigan	Retired before 2018
Edgewater (4)	Wisconsin	10/1/2018
HMP&L Station Two Henderson (1)	Kentucky	Retired before 2018
HMP&L Station Two Henderson (2)	Kentucky	Retired before 2018
James DeYoung (4)	Michigan	Retired before 2018
James De Young (5)	Michigan	Retired before 2018
Kenneth C. Coleman (1)	Kentucky	Mothballed
Kenneth C. Coleman (2)	Kentucky	Mothballed
Kenneth C. Coleman (3)	Kentucky	Mothballed
Pleasant Prairie (1)	Wisconsin	4/3/2018
Pleasant Prairie (2)	Wisconsin	3/23/2018
Pulliam (7)	Wisconsin	10/20/2018
Pulliam (8)	Wisconsin	10/21/2018
R.D. Morrow, Sr. (1)	Mississippi	Retired before 2018
R.D. Morrow, Sr. (2)	Mississippi	7/7/2018
Robert A. Reid (1)	Kentucky	Retired before 2018
Shiras (1)	Michigan	Retired before 2018
Shiras (2)	Michigan	Retired before 2018
Taconite Harbor Energy Center 1	Minnesota	Mothballed
Taconite Harbor Energy Center 2	Minnesota	Mothballed
Meramec (1)	Missouri	Gas conversion
Meramec (2)	Missouri	Gas conversion

Coal plant retirement and conversion updates to Energy Exemplar's 2018_v1 PLEXOS MISO data package used in this analysis. Unit numbers are in parentheses.
SOURCE: SIERRA CLUB 2019 / S&P GLOBAL 2020

The Must-Run Generator Constraint

The model must minimize overall system cost while observing constraints, such as generator must-run constraints. PLEXOS used the generator must-run constraint to represent plants with reliability-must-run designations (known as System Support Resources in MISO) and also to force plants to operate in order to replicate actual operations of power plants even when it was uneconomic to do so.

Scenario Methodology

UCS compared two scenarios: a reference case for 2018 and an economic case. For each scenario, we ran the PLEXOS model for the MISO system with a consistent set of assumptions across MISO.

REFERENCE CASE METHODOLOGY

The reference scenario has two goals: replicating plant dispatch in 2018 to calibrate the model and providing a baseline against which to compare the economic case. For this scenario, UCS:

1. Ran a scenario with the must-run designation turned off for all coal plants;
2. Compared coal generator output data from this scenario with historical coal-plant dispatch data from 2018 based on EIA generation data;
3. Assigned must-run status to individual coal plants that fell below historical 2018 generation data;
4. Turned on must-run designation for 121 units to approximate historical plant dispatch in 2018 to create a reference case.

ECONOMIC CASE METHODOLOGY

The economic case was the result of a UCS analysis to approximate what economically optimal plant operations would look like in MISO in 2018. UCS ran this scenario with the must-run designation turned off for all 207 coal units in MISO except for Trenton Channel Unit 9 in Michigan, which was left as must-run due to known reliability constraints (MISO 2018). The economic case allowed PLEXOS to optimize generator operation without self-commitment to minimize overall system cost while meeting reliability, reserve, and transmission requirements contingent on system and operation constraints, including physical limitations of the power plants.

Production Cost Calculation

Production cost is a model output in PLEXOS. The model minimizes the overall region's production cost while meeting load and observing various constraints such as generator operating conditions (including operating limits, must-run, start-up/shutdown, ramp rates), reserve requirements, and transmission limits. A unit's production cost is defined by PLEXOS using the unit's heat rate, fuel price, and variable operations and maintenance cost (including those costs associated with startup/shutdown).

UCS calculated the difference in production cost between the reference case and the economic case for transmission regions in MISO and for individual coal-generating units. We calculated utility production cost savings/expenditures by aggregating the difference in production cost between the two cases for each generator up to the utility level.

Calculating Import/Export Cost

UCS valued the cost of net imports into or exports from a MISO transmission zone using the clearing price for each zone. Clearing price, a model output for each transmission region, is the load-weighted average of the region's locational marginal price. We calculated the region's net imports/exports using the model's imports/export generation outputs. We then calculated the cost of electricity imports and exports of a transmission region as the model output clearing price for the region multiplied by its net imports/exports.

Calculating the Cost of Delivered Energy

Production costs for a given transmission zone and for the MISO region do not represent the costs to consumers. PLEXOS assigns productions costs based on where those production costs are incurred. If a generator in Local Resource Zone 1 (LRZ 1) produces electricity that serves load in LRZ 2, the production costs are assigned to LRZ 1. Since electricity is transferred into and out of regions to minimize overall regional production cost, the costs associated with imports and exports also need to be calculated.

UCS defined the “cost of delivered energy” as the productions costs for a given zone plus the cost of importing electricity minus the costs associated with generating electricity that is exported to another zone. We calculated the cost of delivered energy for each zone by adding the production cost to the calculated net import cost for each zone and for the entire MISO region. To find the savings/cost of delivered energy for each transmission region and the MISO region as a whole, we calculated the difference in the cost of delivered energy between the reference case and the economic case.

Appendix D
Model Outputs and Results

Utilities and Power Plants	Gross Benefits of economic commitment ($)	Capacity (MW)	Transmission Zone/ State	Number of Residential Accounts
Cleco Power LLC	$123,253,653	1,131	9	244,782
Brame Energy Center (Rodemacher 2)	$7,190,845	493	LA	
Dolet Hills	$116,062,808	638	LA	
DTE Electric Company	$94,741,423	6,256	7	1,992,276
Belle River	$8,503,255	1,270	MI	
Monroe	$18,836,129	3,086	MI	
River Rouge	$1,158,069	280	MI	
St Clair	$63,431,243	1,100	MI	
Trenton Channel	$2,812,726	520	MI	
Northern States Power Company	$56,925,716	2,749	1	1,149,958
Allen S. King	$6,962,270	511	MN	
Sherburne County Plant (Sherco)	$49,963,447	2,238	MN	
Duke Energy Indiana, LLC	$54,039,268	5,072	6	724,302
Cayuga	$11,155,362	1,005	IN	
Edwardsport	$7,479,055	630	IN	
Gibson	$21,853,041	3,157	IN	
R. Gallagher	$13,551,810	280	IN	
Union Electric Company	$43,782,009	5,295	5	1,060,493
Labadie	$21,864,682	2,462	MO	
Meramec	$474,870	619		
Rush Island	$5,579,056	1,222	MO	
Sioux	$15,863,402	992	MO	
Consumers Energy Company	$25,061,878	1,721	7	1,603,125
Dan E Karn	$301,427	258	MI	
J.H. Campbell	$24,760,451	1,463	MI	
Dairyland Power Co-op	$23,905,106	690	1	-
Genoa	$12,822,494	300	WI	
John P Madgett	$11,082,612	390	WI	
Northern Indiana Public Service Company	$20,125,538	2,094	6	412,267

Michigan City	$1,665,103	469	IN	
R.M. Schahfer	$18,460,435	1,625	IN	
Wisconsin Power and Light Company	$18,419,492	1,561	2	413,571
Columbia Energy Center	$12,258,346	1,156	WI	
Edgewater	$6,161,146	405	WI	
Wisconsin Electric Power Company	$18,291,623	2,263	2	1,012,377
Elm Road Generating Station (Oak Creek)	$9,681,172	1,268	WI	
South Oak Creek	$8,610,451	995	WI	
Dynegy Midwest Generation, Inc.	$17,861,127	2,543	4	-
Baldwin Energy Complex	$6,551,332	1,815	IL	
Havana 6	$5,457,083	434	IL	
Hennepin Power Station	$5,852,712	294	IL	
Otter Tail Power Company	$15,875,448	1,041	1	48,497
Big Stone	$5,896,049	474	SD	
Coyote	$5,310,683	429	ND	
Hoot Lake	$4,668,716	138	MN	
MidAmerican Energy Company	$14,798,043	3,420	3	591,461
George Neal North	$2,625,003	510	IA	
George Neal South	$2,125,937	644	IA	
Louisa	$2,486,866	744	IA	
Walter Scott, Jr. Energy Center	$7,560,237	1,522	IA	
Southern Indiana Gas and Electric Company	$14,635,509	850	6	123,587
A.B. Brown	$7,219,609	490	IN	
F.B. Culley	$7,415,900	360	IN	
Illinois Power Generating Company	$14,132,243	1,530	4	-
Coffeen	$8,678,260	915	IL	
Newton	$5,453,983	615	IL	
ALLETE (Minnesota Power)	$13,705,604	1,104	1	122,557
Clay Boswell	$13,705,604	949	MN	
Taconite Harbor Energy Center	$0	155	MN	

Illinois Power Resources Generating, LLC	$11,134,949	1,010	4	-
Duck Creek	$3,978,292	425	IL	
E.D. Edwards	$7,156,657	585	IL	
Hoosier Energy Rural Electric Coop Inc.	$9,600,685	996	6	-
Merom Generating Station	$9,600,685	996	IN	
Indianapolis Power & Light Company	$9,457,882	1,732	4	440,693
Petersburg	$9,457,882	1,732	IN	
Prairie State Generating Company, LLC	$9,146,393	1,627	4	-
Prairie State Energy Campus	$9,146,393	1,627	IL	
Big Rivers Electric Corporation	$8,598,878	1,314	6	-
D.B. Wilson	$4,185,290	417	KY	
K.C. Coleman	$0	443	KY	
R.D. Green	$4,413,588	454	KY	
Interstate Power and Light Company	$7,915,616	1,347	3	403,726
Burlington ST	$858,181	216	IA	
Lansing	$607,709	230	IA	
Ottumwa	$6,228,967	730	IA	
Prairie Creek	$220,760	171	IA	
Great River Energy	$7,766,074	1,232	1	-
Coal Creek	$7,306,963	1,142	ND	
Spiritwood Energy Cogen Plant	$459,111	90	ND	
Montana-Dakota Utilities Co.	$7,280,437	148	1	19,918
Lewis & Clark	$1,205,921	44	MT	
R.M.Heskett Generating Station	$6,074,516	104	ND	
Entergy Arkansas, LLC	$6,985,754	3,321	8	593,203
Independence	$3,624,460	1,681	AR	
White Bluff	$3,361,294	1,640	AR	
Southern Illinois Power Cooperative	$5,049,274	290	4	10,821
Marion	$5,049,274	290	IL	
Lansing Board of Water & Light	$4,815,373	353	7	-
Eckert Station	$3,998,664	197	MI	
Erickson	$816,709	156	MI	

Minnkota Power Cooperative, Inc.	$4,350,995	692	1	-
Milton R. Young	$4,350,995	692	ND	
Wisconsin Public Service Corporation	$3,857,889	873	2	390,585
Weston	$3,857,889	873	WI	
AGC Division of APG Inc	$3,421,919	249	6	-
Warrick	$3,421,919	249	IN	
TES Filer City Station LP	$3,420,678	60	7	-
TES Filer City Station	$3,420,678	60	MI	
Springfield City of - (IL)	$3,263,305	534	4	60,107
Dallman	$3,263,305	534	IL	
Archer-Daniels-Midland Company	$3,171,023	322	3	-
Cedar Rapids	$944,810	169	IA	
Clinton	$2,029,174	78	IA	
Decatur	$197,039	74	IL	
Muscatine Power and Water	$2,700,672	204	3	-
Muscatine	$2,700,672	204	IA	
Entergy Louisiana, LLC	$2,015,063	550	9	933,009
R.S. Nelson	$2,015,063	550	LA	
NRG Energy Services LLC	$1,628,193	670	8	-
Plum Point Energy	$1,628,193	670	AR	
Iowa State University	$1,004,334	30	IA	-
Iowa State University	$1,004,334	30	IA	
Cleveland-Cliffs Inc.	$696,904	105	1	-
Silver Bay Power Company	$696,904	105	MN	
University of Iowa	$341,268	15	IA	-
University of Iowa	$341,268	15	IA	
Louisiana Generating LLC	$136,466	1,168	9	-
Big Cajun 2	$136,466	1,168	LA	
Willmar Municipal Utils Comm	$79,292	16	1	7,999
Willmar	$79,292	16	MN	
Grand Haven City of	$76,174	70	7	12,432
J.B. Sims	$76,174	70	MI	
Columbia City of Missouri	$60,852	22	5	43,519

Columbia, MO	$60,852	22	MO	
University of Northern Iowa	$42,666	2	IA	-
University of Northern Iowa	$42,666	2	IA	
Sidney Sugars Incorporated	$36,977	1	1	-
Sidney MT Plant	$36,977	1	MT	
Hibbing Public Utilities Comm	$28,440	36	1	6,095
Hibbing	$28,440	36	MN	
Macquarie Group Ltd.	$19,685	19	3	-
Cargill Corn Milling Division	$19,685	19	IA	
Cedar Falls Utilities	$7,237	16	3	17,216
Streeter Station	$7,237	16	IA	
Crawfordsville Energy LLC	$816	23	6	-
Crawfordsville	$816	23	IN	

SOURCE : Power plants listed by primary owner based on EIA, number or residential customers based on EIA, MISO zone identification based on Energy Exemplar. Gross benefit of economic commitment calculated by UCS.

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ENDNOTES

1. Weighted average across all major US ISO/RTO energy markets based on percent of megawatt-hours. Portion of ISO/RTO generation that is owned by independent power providers versus investor owned or public owned power varies by market.
2. For more information on restructuring, see https://www.e-education.psu.edu/eme801/node/534.
3. Weighted average across all major US ISO/RTO energy markets based on percent of megawatt-hours. Portion of ISO/RTO generation that is owned by independent power providers versus investor owned or public owned power varies by market.
4. FERC Order 745 requires ISO/RTOs to allow for participants in the wholesale markets to either provide the supply of energy (in the form of electric generation of energy) or reduce demand in the form of demand response. All major US ISO/RTOs also operate real-time energy markets in five-minute increments.
5. Production costs include not only fuel but also variable operation and maintenance costs needed to produce a unit of energy. They exclude fixed operating costs, which would include fixed payments like debt or rent. Production costs are only incurred when the power plant is producing electricity while incurring fixed costs regardless of the plant's output.
6. Dark spread can be a generic measurement of coal using spot market and can be calculated at different levels of geospatial and temporal granularity.
7. Cleco co-owns the Dolet Hills coal plant along with SWEPCO. Savings from reduced operations would flow to customers of both companies.
8. Seasonal operation has also been referred to as seasonal shutdown, seasonal idling, and taking a coal holiday.
9. See https://www.youtube.com/watch?v=JSGTuJK5mnY&feature=youtu.be.
10. The initial report on economic dispatch was conducted pursuant to the Energy Policy Act of 2005 (DOE 2007).

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