Backdoor Subsidies for Coal in the Southwest Power Pool

Are Utilities in SPP Forcing Captive Customers to Subsidize Uneconomic Coal and Simultaneously Distorting the Market?

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Executive Summary

The terrain that stretches from North Dakota through the Panhandle of Texas is vast, but what the region shares is a booming wind energy industry coupled with an aging set of coal-fired power plants. This particularly affects the Southwest Power Pool, the energy grid operator that ties the region together and provides power for millions of Americans.

The Southwest Power Pool, often abbreviated as SPP, provides the opportunity for electric utilities to gain access to low cost electric power so it can be delivered it to customers. SPP set a record in early 2017 when it served customers more than 50 percent of their power with wind energy.[1]

Wind energy has been taking off at a record-setting pace in the SPP, but analysis outlined in this report found that some utilities participating generating electric power in the SPP market might be operating more expensive power units when less expensive options are available. This report found—most troublingly—that several utilities might be hurting captive customers by propping up expensive coal plants and distorting the proper operation of the SPP energy market.

According to our analysis, several utilities are distorting the SPP market by over-operating expensive coal-fired power plants it owns, even if it's more costly, instead of taking advantage of lower cost energy sources available in the SPP market from other generators. Utility captive customers who have no choice in the matter pay for the subsidy on their monthly electric bills, which highlights the importance of utilities not operating its expensive coal plants when SPP electricity is available at prices below the cost of operations.

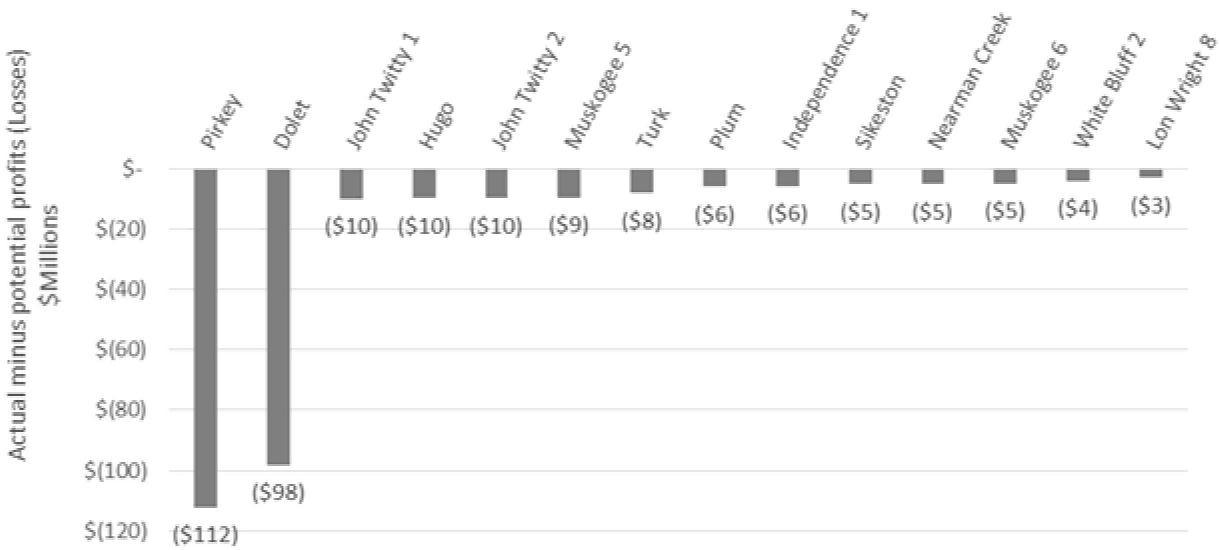
We began with a first-cut analysis in which we examined how often each electric generating unit in the SPP territory was operated by its owners in 2015 compared to how often we might have expected that power station to operate. Using the economic theories at the heart of market design and the principle that consumers are entitled to lowest cost power, the first-cut analysis flagged 20 coal-fired units that were operating significantly more than would otherwise be expected.

For 14 of the 20 potentially over-operating coal units that were identified during the first-cut analysis, we then conducted a high-resolution analysis that examined the hourly operations of each of those units and used hourly market data to develop a cash flow analysis for each of them. Our results showed that all 14 units operated for extended periods of time when, objectively, it would have been less expensive for the electric bills of utility customers for the plants to sit idle. The utilities that own each of the 14 coal units we examined would have saved its customers money if the coal units had operated less often. In 2015 and 2016, the impact of these sub-optimal operations amounted to $300 million in higher electric bills from just the 14 units we selected to analyze.

Figure ES 1 shows the actual net energy revenues minus the potential net energy revenues of each of the 14 units we analyzed. Between 2015 and 2016, the two year burden for utility customers was $300 million.

[1] SPP. "SPP sets North American Record for Wind Power." February 13, 2017. Retrieved online. https://www.spp.org/about-us/newsroom/spp-sets-north-american-record-for-wind-power/

Figure ES 1. Ratepayer benefit (burden) from uneconomic dispatch.



Source: Calculations based on data from S&P Global Market Intelligence
note: Independence, White Bluff, Plum Point, and Dolet Hills have owners in SPP and MISO

Most of the coal units analyzed were not recovering all of the energy production related costs from the energy market over the two-year study period. While a few units appeared to have positive cash flow on a one or two year basis (ignoring fixed costs), all of these units operated at a loss on a monthly basis for six to nine consecutive months. The utilities are using customers' money to subsidize the operations of coal plants during long periods of time when less expensive power was available.

Utilities are able to get away with this because utilities can take advantage of the complex nature of rate design, rate cases, and market rules. This complexity and lack of transparency creates a system where customers buffer and fill in the gap of a utility's market losses. In addition to forcing captured utility customers to pay higher prices for electricity, the practice also harms proper SPP market operations by:

1. Displacing lower-cost, more efficient units, depriving them of market revenues; and
2. Artificially suppressing market revenues to other generators in nearby areas, which deprives them of revenues and discourages more cost-efficient energy, including clean energy resources, from coming onto the market

Because monthly electric bills for utility customers in SPP are determined by traditional rate making at state commissions, not the SPP electricity market, certain utilities appear willing to operate plants in the SPP energy markets that cannot cover the fuel and operating costs with revenues from SPP energy markets, because it can make up the difference through ratemaking with state commissioners. In order to mitigate and hopefully prevent this problem in the future, this paper makes the following policy recommendations:

1. Utilities are ultimately responsible for the decision to operate otherwise uneconomic units via self-dispatch in the SPP energy markets. In order to fulfill the legal requirement generally present across the SPP states to provide customers with lowest cost power, utilities should stop engaging in uneconomic behavior.

2. Moreover, utilities charge customers rates that are approved by state public service commissions and those regulators have the duty to protect consumers. Regulators like FERC and state public service commissions have a myriad of options available to them, including disallowing the recovery of costs for fuel and other expenses associated with time periods of

uneconomic coal plant operations when the utilities come to the commissions during rate making.

3. The practice of self-dispatch by certain utilities in SPP is bad for customers and could be stunting development of other energy resources by suppressing market revenues to other market participants in the areas around utility-owned generation. SPP and the SPP Market Monitor should prevent this kind of market behavior through better market operations.

How Are Energy Markets Supposed to Work?

Within the United States, there are seven independent system operators (ISOs), or regional transmission organizations (RTO), that operate the country's energy markets: ISO New England (ISONE), New York ISO (NYISO), PJM, Midcontinent ISO (MISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), and California ISO (CAISO). These ISOs provide multiple services including acting as a centralized body that coordinates generation and transmission activities that ultimately matches supply with demand. Each of these RTOs operates an energy market and although the rules of each RTO's energy market vary, there are a few economic principles that are common across all of them (discussed in the Energy Markets Primer, below).

RTOs are regulated by the Federal Energy Regulatory Commission (FERC).[2] FERC's authority over RTOs principally arises from its jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce."[3] The Federal Power Act requires rates for jurisdictional transmissions and sales to be "just and reasonable."[4] The law also prohibits any undue preference, advantage, prejudice, or disadvantage, as well as any unreasonable difference in rates, as part of FERC-jurisdictional transmissions and sales.[5] FERC's role in determining whether rates are just and reasonable has largely moved from approving specific tariffs based on cost of service to reviewing whether market rules produce competition outcomes, and therefore just and reasonable prices.

Energy Market Primer

Energy markets are reverse auctions where sellers bid in a price and the market selects the lowest cost resources needed to meet demands for electricity in a secure and reliable way. Only the lowest cost resources are used to meet load. The marginal resource that is *called* by the market (i.e., instructed to generate energy or, in the case of demand response, reduce demand) is the most expensive resource that is needed to serve load. All resources called in a given hour are paid the clearing price as set by the bid of the marginal resource. This structure creates incentives that put less efficient and more expensive supply source at a disadvantage, a process that when functioning properly is good for consumers and can be good for the environment.[6]

Energy markets are designed to offer appropriate incentives known as "price signals" - to encourage new resources to enter the market, thereby maintaining adequate supply for reliable electric service while simultaneously keeping costs down for consumers. However, as we explain in this report, improper market implementation creates economic distortions that can keep uneconomic generation online at the expense of captured customers and more efficient competitors.

All energy markets, including SPP, achieve the above goals through a process known as locational marginal pricing (LMP). In an energy market, owners of generating assets offer a price (in dollars) to generate a specific quantity of power (in megawatts, MW) in every hour of the day. For each hour of the day, those offers are then assembled to generate a supply curve (also referred to as a merit order bid stack), represented by the green line in the below figure. In a properly functioning market, the offer price is supposed to represent the cost to supply a unit of energy by that generator, which for

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[2] Because ERCOT does not engage in inter-state energy trading it is generally not subject to FERC jurisdiction. See, e.g., Electric Energy Market Competition Task Force, Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy, at 55 (2007). Available online: http://www.ferc.gov/legal/staff-reports/competition-rpt.pdf.

[3] 16 U.S.C. § 824(b)(1) (2012).

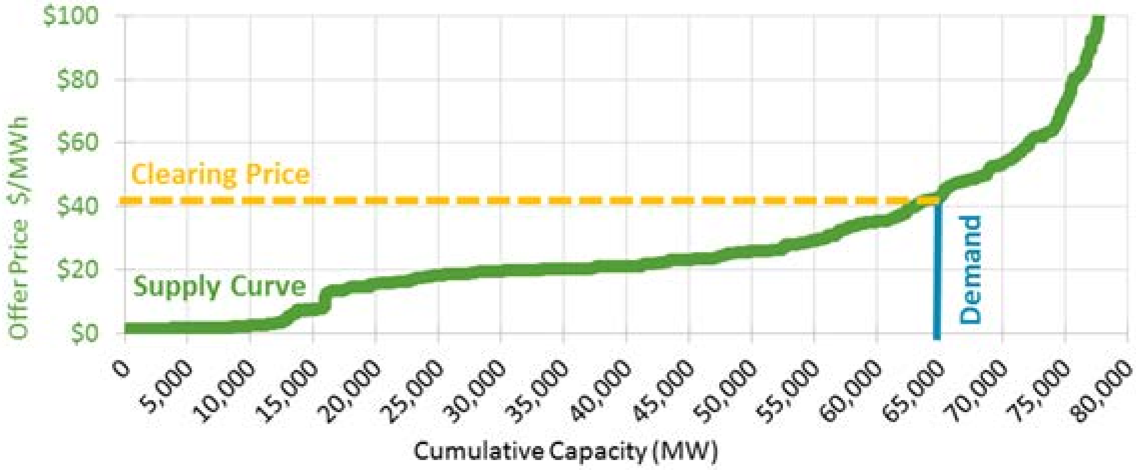
[4] § 824d(a).

[5] § 824d(b).

[6] A properly functioning market, in this context, requires adherence to basic competitive market principles including an absence of negative externalities.

coal and gas units is typically dominated by fuel costs but also includes other costs that dependent on how often the unit is operating. Costs that vary with operation are called variable costs; cost that stay fixed, regardless of operation, are fixed costs. For a coal or gas fired power plant, variable costs would include fuel costs and costs to consume other products like water or chemical reagents used in environmental controls. The variable cost for resources like wind and solar are generally zero or nearly zero dollars, because there is no cost associated with buying the fuel. The ISO assembles the bids, orders the lowest cost offers first, followed by each incrementally more costly offer. The last, incremental (marginal) offer to be accepted is the clearing price. And because this bidding process includes a geographic element, the clearing price for a given location is the locational marginal price. For each hour of the day there is also an associated demand--*i.e.*, the amount of energy that consumers need to meet energy demand--represented by the blue vertical line in Figure 1. The market then procures energy from the lowest cost resources, including supply side resources like electric generating units and demand side resources like demand response,[7] up to the point that meets demand in that hour, creating a clearing price, represented by the dashed yellow line in Figure 1. A unit is said to "clear the market" if its place in the supply curve is at or below the clearing price.

Figure 1. Illustrative Figure for LMP (clearing price)



So, in the illustrative figure above, the demand is 65,000 MW, and as a result the first 65,000MW of the lowest cost offers clear the market. The clearing price is $41/MWh, and all units that clear the market get paid the clearing price. If an owner of a generating asset offers a bid to generate energy $20/MWh (based on that unit's costs) and the clearing price is $41/MWh, then that owner will net $21/MWh. So, why don't owners underbid so to guarantee it is called to operate? Why don't resources overbid to make more money?

Generators <u>should</u> make offers that reflect the variable costs of production, which includes fuel, pollution control operating costs, and other variable operation and maintenance costs. Under such a bidding framework, a generator will recover its variable or marginal operating costs via energy market revenues and may recover a portion of its fixed costs only if it has operating costs that are below the LMP clearing price. To not use such a bidding paradigm would mean that a generator could either fail to cover its variable operating costs and operate at a financial loss (by underbidding) or lose the opportunity to participate in the marketplace (by overbidding).

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[7] FERC orders 719 and 745, ISOs are required to allow demand response resources to participate in energy markets on equal terms as generators. See also *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760 (2016).

To illustrate this, Table 1 evaluates the outcomes of owners' decisions to either bid the unit's marginal cost, underbid (i.e. offer a price that is below the unit's marginal cost), or overbid (i.e. offer a price that is above the unit's marginal cost).

Table 1 Illustrative bid offers and clearing prices. Blue cells represent utility's net energy revenues.

Marginal Cost = $30.00		Clearing Price **$ 26.00**	**$ 31.00**	**$ 36.00**
Offer Price	**$ 25.00**	$ (4.00)	$ 1.00	$ 6.00
	$ 30.00	n/a	$ 1.00	$ 6.00
	$ 35.00	n/a	n/a	$ 6.00

Source: Author's Calculations

Table 1 assumes that a hypothetical generation asset has a marginal cost of $30. If the owner of the generation asset bids $25 to generate a megawatt of energy (offer price) and the clearing price is $26, the unit would get called and the owner would lose $4.00 for each MW it was called on to supply. Moreover, the low bid does not give the generator any advantage when the clearing price actually rises above the generator's marginal cost; the generator's net energy revenues are always the difference between the market clearing price and the generator's marginal cost. Conversely, if the owner overbids, say it bids a price of $35 per megawatt hour, then the unit won't get called when the clearing price is $31 thereby losing out on an opportunity to make some profit. And again, even if the clearing price does rise high enough for the unit to be called with a $35 bid, the generator's profit is the same as if it had bid $30, its marginal cost. Table 1 thus illustrates that a firm seeking to maximize profits would only ever offer a bid price equivalent to a unit's marginal cost. To under-bid would expose the firm to being called on and being paid less than the price it costs them to generate energy. To over-bid would expose the firm to lost opportunities to make revenues when it is otherwise economic to do so.[8] In this way, the LMP model helps to ensure that energy providers do not under or over-bid energy offers. Operating at a loss in the short term, and especially in the long term, is irrational unless there is some other explanation. This report will show that there is another explanation: the ability of some units to recover losses from captive customers.

The second objective of LMP is to encourage the entry of new, lower-cost, more efficient generators into the market. Because all generators are paid the same price, the lower-cost generators can make the most profits.[9] So, in an energy market where LMP is typically above$35/MWh, a resource that costs $30 to generate a megawatt of energy would be able to enter the market and make a profit—namely, a $5 "profit" for each unit of energy it sells (fixed costs aside). This should create a cycle in which cheaper (and generally newer) resources enter the market and push out more expensive, less efficient resources. This will drive down the price, at which point more expensive, less efficient resources won't be able to compete. Non-competitive resources will retire, reducing supply and thereby driving prices back up, which will send price signals for new units to enter, continuing the cycle.

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[8] In reality, economics alone don't monitor bid behavior; bid behavior is also reviewed by the independent market monitor. This independent agency monitors bids and pays close attention to market manipulation.

[9] This, of course, doesn't take into account the fixed costs of resources that don't vary with the unit's output.

The Southwest Power Pool

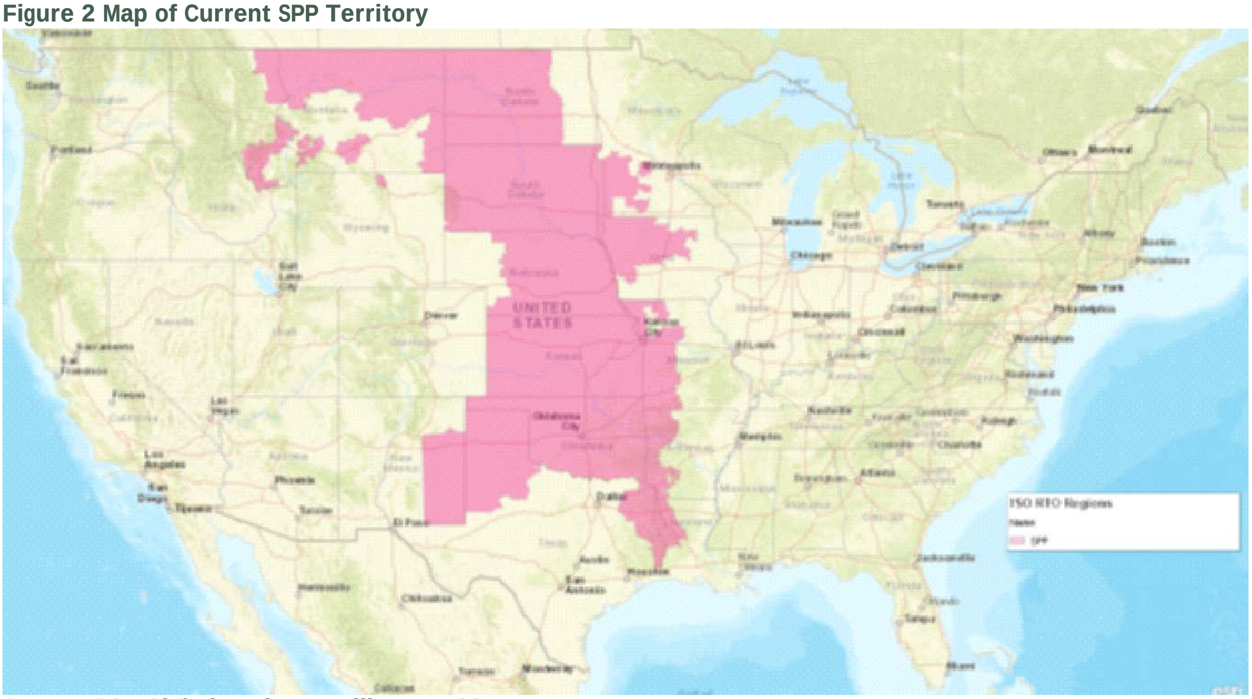
A Brief History of SPP

Southwest Power Pool has its origins in 1941, when 11 regional power companies coordinated to keep an aluminum smelter in Arkansas powered around the clock to meet wartime needs for materials. After WWII, SPP's Executive Committee decided that the organization should continue to help maintain electric reliability and coordination in the region. In 1968, SPP worked with 12 other entities to form what is now the North American Electric Reliability Corporation (NERC), a non-profit corporation in charge of setting electric reliability standards. More recently, SPP incorporated as an Arkansas nonprofit organization in 1994. The Federal Energy Regulatory Commission (FERC) approved SPP as a RTO in 2004. SPP expanded its operations in 2015 to serve all or parts of 14 states.[10]

SPP Today

SPP’s footprint spans portions of 14 states: Montana, North Dakota, South Dakota, Minnesota, Iowa, Missouri, Wyoming, Nebraska, Kansas, Oklahoma, Arkansas, Texas, New Mexico, and Louisiana. Figure 2 displays the territory currently encompassed by SPP.

Figure 2 Map of Current SPP Territory



Source: S&P Global Market Intelligence, 2017.

At the time this analysis was being conducted, the Mountain West Transmission Group Initiative, an “informal collaborative of electricity service providers,” was considering a range of options including joining an RTO like SPP.[11] Were these utilities in that initiative to join SPP, its territory would grow

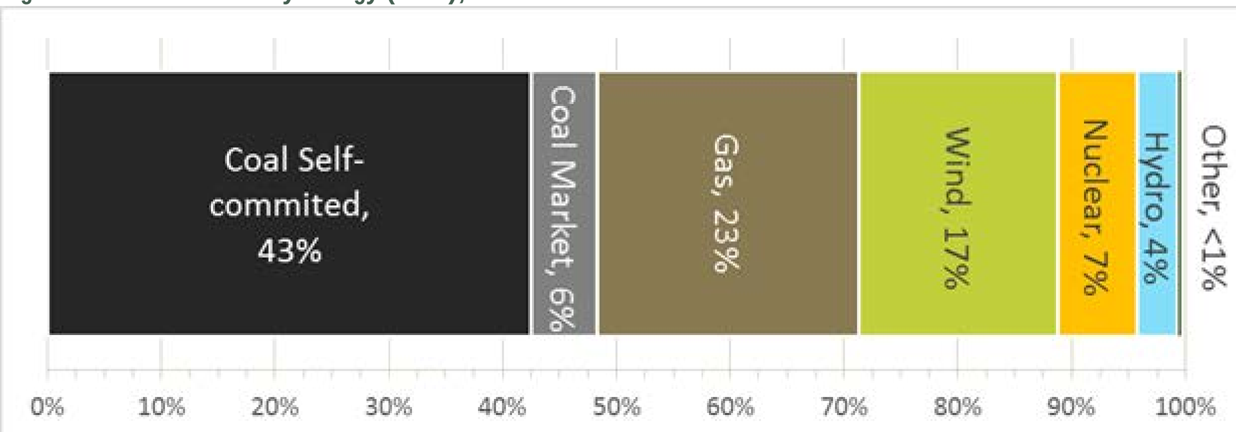
[10] SPP, “Economies of Scale: The Benefits of SPP’s Markets, Today and in the Future.” Available online: https://www.spp.org/documents/16503/present%20&%20future%20market%20benefits.pdf.

[11] Western Area Power Administration, “Mountain West Transmission Group.” Available online: https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx.

in Montana, Wyoming, Nebraska, Kansas, and New Mexico, and would expand into three new states, Utah, Arizona, and Colorado. The process of joining SPP was still underway at the time of this analysis, so this report does not evaluate the possibly expanded service territory. On September 22, 2017, Mountain West Transmission Group announced that it would be moving forward with joining SPP.[12]

The energy mix of SPP has changed over time, particularly as the territory has expanded. Advancements in wind turbine technology making wind energy more cost-competitive, along with increased public demand for clean energy, have resulted in a rapidly increasing amount of wind energy coming onto the SPP grid. In 2008, wind energy comprised only 1% of generation in the SPP territory,[13] while in 2016 that number rose to 17%.[14]

Figure 3 SPP's Fuel Mix by Energy (MWh), 2016



Source: SPP Integrated Market Data for 2016.[15]

Coal Self-commit

In 2016, almost half (48 percent) of the energy generated in SPP still came from coal.[16] However, as this report will show, not all coal generation is being selected by the market to operate based on economic merit. Rather, as shown by Figure 3, less than 10% of SPP energy mix comes from coal being dispatched by the market, while over 40 percent comes instead from coal plants that are "self-committed" to operate.

Within SPP there are two energy markets, a day-ahead market and a real-time market. The day-ahead market seeks bids the day prior to when energy will be needed, based on a projection of what demand is going to be. Within all US energy markets, 95 percent of all energy transactions are

[12] Western Area Power Administration. "Mountain West Announces Next Step to Potential Southwest Power Pool Membership" (September 22, 2017). Available online: https://www.wapa.gov/newsroom/NewsReleases/2017/Pages/Mountain-West-SPP-negotiations.aspx

[13] SPP, 2008 Annual Report, at 7. Available online: https://www.spp.org/documents/9510/spp%202008%20annual%20report.pdf

[14] SPP Market Monitoring Unit, "State of the Market 2016," at 51. Available online: https://www.spp.org/documents/49962/2016%20annual%20report%20-%20web.pdf.

[15] SPP Integrated Marketplace, 2016 Generation Mix. Available online: https://marketplace.spp.org/pages/generation-mix-historical.

[16] SPP Integrated Marketplace, 2016 Generation Mix (numbers may not match due to rounding). Available online: https://marketplace.spp.org/pages/generation-mix-historical.

scheduled in the day-ahead market.[17] The real-time market operates as a supplement to the day-ahead market, to help balance the actual load observed in real time with the energy supply.

SPP allows generators to "self-commit" or "self-schedule" into the day-ahead market. For coal units, this is sometimes referred to as "coal self-dispatch." When a utility self-commits a unit, the unit will be operated by the utility whether or not the revenues for electricity provided by SPP are sufficient to cover the marginal costs for making the electricity, let alone sufficient to provide a profit to the utility. These coal-fired units that self-commit are, at best, 'partial participants' because the self-committed resources do not respond to the market's price signals. Such coal units operate regardless of the clearing prices and it operates regardless of the revenues it receives from SPP to generate electric power. According to the SPP market monitor:

> *Some of the reasons for [self-commitment] may include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, and a risk-averse business practice approach.*[18]

Notably, while there are a number of explanations to why a unit might self-commit, reliability isn't one of them. While utilities that operate within SPP do have reliability requirements, including maintaining a certain amount of available capacity to cover peak demand and a reserve margin, this requirement doesn't require them to self-commit. It is also worth noting that the SPP integrated marketplace reports data on types of resources that are operating within its territory; though coal is not the only fuel allowed to self-commit, coal is the only fuel that reports data with a special breakout of market versus self-committed.[19]

If LMP in the day-ahead market is hovering around a self-committing coal unit's marginal cost, the unit's operator may choose to just run the plant on the assumption that the profits it makes when LMP is above the unit's marginal cost will outweigh the losses when the LMP is below the unit's marginal cost.

If an electric generating unit is called to operate by the market rather than through self-commitment, the market rules are designed to ensure that unit is "made whole." SPP explains that

> *The Integrated Marketplace provides make-whole payments (MWPs) to generators to ensure that the market provides sufficient revenue to cover the short-run marginal cost of resources that provide energy, start-up, no-load, and operating reserve products for a market commitment period and for local reliability commitments. Make-whole payments are additional market payments in cases where prices result in revenue that is below a resource's cleared offer. These payments are intended to make resources whole to the costs of providing the above-mentioned products.*[20]

Thus, units that are committed by the day-ahead market are given reassurances that the costs it incurs to operate in the day-ahead market are covered; however, only entities that are called by the

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[17] FERC. "Energy Primer: A Handbook of Energy Market Basics," at 59. Available online: https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

[18] SPP Market Monitoring Unit, "State of the Market 2016." Available online: https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf.

[19] SPP Marketplace. Generation Mix. Available online: https://marketplace.spp.org/pages/generation-mix-rolling-365.

[20] SPP Market Monitoring Unit. "State of the Market 2016," at 7. Available online: https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf.

market are eligible, so self-committed units are ineligible to receive make whole payments.[21] Entities that are truly participating in the market are essentially guaranteed to at least break even at the end of the day. However, units that self-commit are theoretically at risk of operating at a loss. The units might self-commit a unit during times where market revenues are insufficient over the short term and long term to cover the cost of operating the unit, let alone to operate and provide a profit.

Following the model described in the previous section, Energy Market Primer, operating at a loss in the short term, and especially in the long term, is irrational unless there is some other explanation. This report will show that there is another explanation—the ability of some units to recover losses from captive customers. To investigate this explanation, we first looked into whether the SPP market is behaving as expected. Our findings, reported in the next section, are that a significant portion of the SPP fleet is not behaving as expected. Then, to nail down the possible explanations for such behavior, we "follow the money" in a later section.

Is the SPP Market Behaving as Expected?

In an energy market like SPP, the expectation is that low-marginal-cost units operate as much as possible and high-marginal-cost units operate less. If expensive coal units are operating more often than it should, then this might alter which units are called on and distort the overall costs of the system. Significant distortions to this tenet of energy markets undermine the proper functioning of the market. Given how much energy procured through SPP's markets is self-committed, is it possible that the practice is distorting the market and preventing it from functioning properly?

There are nearly 1,700 electric generating units (EGUs) that operate in SPP.[22] In order to investigate if EGUs are being dispatched economically into the SPP markets, we developed a screening test to broadly flag which units might be dispatching more than the economics would predict.[23] In general, the lower cost units should have the higher capacity factors, whereas the higher cost units should have the lower capacity factors. We examined the basic economics of all 1,700 EGUs and then grouped them into categories depending on the degree to which each EGU's dispatch is consistent with what economics would predict.

In order to investigate which units are operating more often market economics alone would predict, we conducted a screening analysis. The analysis was designed based on the very simple idea that low variable cost resources should operate most often and more expensive units should operate less often. The detailed description of the methodology and results can be found in Appendix 1. Based on the results of the screening analysis, units that were identified as operating inconsistent with what market economics alone would expect, we conducted a higher-resolution analysis using more granular data.

High-Resolution Analysis

The next step of our analysis was to look at hourly deviations from the dispatch that would be expected under market principles. For the hourly analysis, "high-resolution analysis," we looked at those units whose deviation was greatest. We then further pared down the list based on units for which the requisite data (hourly generation data and fuel receipt data) wasn't available. The high-resolution analysis was designed to account for the geographic and temporal fluctuations in prices and was conducted in order to resolve any uncertainty in the results of the screening analysis.

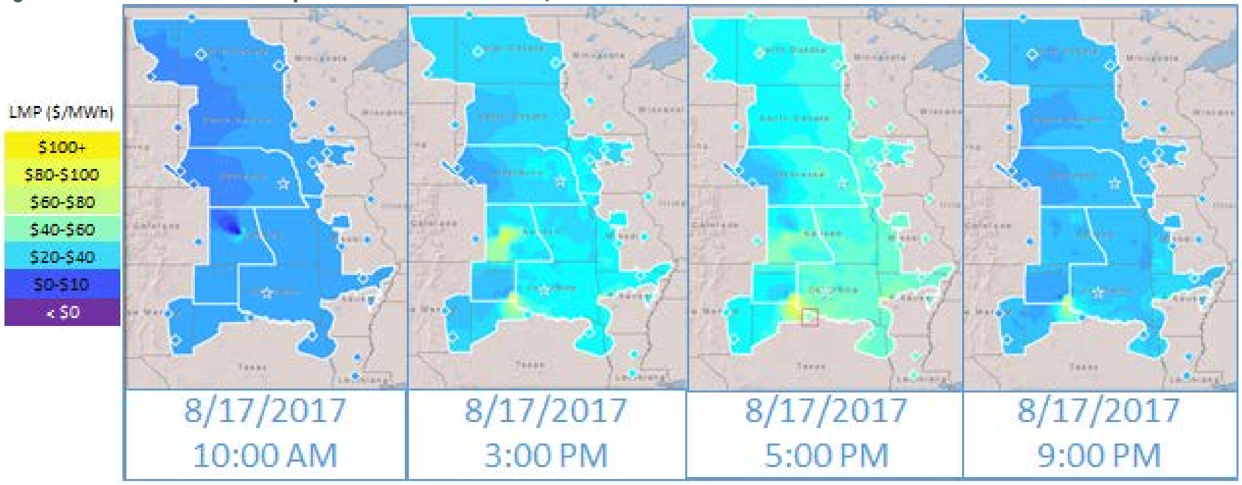
[21] SPP, "Integrated Market Place" (Commission staff education presentation), March 26, 2012, at 95.

[22] S&P Global Market Intelligence.

[23] The screening test was designed to be a first cut analysis, to help determine which units required a more in-depth analysis. The results are designed to be relative and not absolute.

Prices within SPP not only vary over the course of the day, but also across the SPP territory. Figure 4 illustrates the temporal and spatial changes within SPP on a sample day.

Figure 4. Price Contour Map of SPP on 8/17/2017, select time slices.



Source: SPP Price Contour Map for 8/17/2017 at 10:00, 15:00, 17:00, 21:00.[24]

Warmer colors in Figure 4 represent "hot spots" of areas where the market is clearing at higher prices. One of the more common causes for these hot spots are transmission constraints: sometimes constraints exist and haven't been addressed by new transmission projects, sometimes constraints are created by planned maintenance or unplanned events. If there are two equally expensive units operating within SPP, one in a location that is a regular hot spot, one outside of a hot spot, it is likely that the one in the hot spot would be relatively more economic to operate, while the other would likely be less profitable. One would also expect the one in the hot spot to operate more often (assuming both units have similar operational capabilities). While it is likely that the coal unit in the hot spot is more profitable, it is also possible that neither, or both, would be economic to operate. The best way to address this is to conduct an hourly analysis that accounts for the geospatial price fluctuations. Our high-resolution analysis does just that.

The high-resolution methodology maps specific coal plants to the geographically closest nodes in order to account for different locational marginal prices that each resource gets paid. Then, we use hourly LMP data for each of those nodes and map it to the hourly generation of each of the coal units. Multiplying these two values, LMP (in $/MWh) and generation (MWh), provides us with an hourly level energy revenue value. We then compare this value to the costs to operate the plant to determine which units are operating at a loss, and which units are covering that unit's energy-related costs.

High-Resolution Methodology

The high-resolution analysis accounts for both the temporal and spatial issues not addressed by the screening analysis, and is based entirely on data submitted by either the utilities or the SPP market. The analysis used tools provided by SNL and S&P Global to aggregate various public data sources, including locational data. We know that the majority of coal dispatched into SPP is not committed by the market, but this analysis focuses on which coal resources are dispatched into SPP might be negatively affecting the market. As a result, we limited the analysis to a select few of the worst actors based on the screening analysis.

[24] SPP, Price Contour Map (2017). Available online: http://pricecontourmap.spp.org/pricecontourmap/.

Step 1: Mapping Units to Node

Using S&P Global mapping tools, each unit was displayed on a map of the SPP territory along with the location of every node and hub within SPP. Matching each unit with the corresponding node was based on proximity and name. For example, the Dolet Hills coal plant in Louisiana was matched to the node with its own name in it, CSWS_OMPA_DOLETHILLS.

Some of these units in SPP, like Dolet Hills, White Bluff and Independence, dispatch into both SPP and a neighboring RTO, MISO. There is no publically available data that would conclusively determine which RTO a given unit is dispatching in any given hour. So, this analysis is forced to make an assumption about the portion of each hour's generation that is used to serve SPP. For each plant, we use data supplied by S&P Global on the portion of the unit that dispatches into SPP.

Table 2 List of Selected Plants with Geospatially Mapped Node.

Plant Name	State	Geospatially Mapped Node	Percent Dispatched into SPP
Dolet Hills Power Station	LA	CSWS_OMPA_DOLETHILLS	50%
H W Pirkey Power Plant	TX	CSWS_OMPA_PIRKEY	100%
Hugo	OK	WFEC_HUGO_PLANT	100%
Independence	AR	OKGERAZRBAK2LD	29%
John Twitty Energy Center	MO	SPRM_SWCT	100%
John W. Turk Jr. Power Plant	AR	CSWSWTURK	96%
Lon D Wright Power Plant	NE	FREM_LOAD	100%
Muskogee	OK	OKGEMUSKOGEEUN	100%
Nearman Creek	KS	KACYNEARMANUN	100%
Plum Point Energy Station	AR	SPP PLUM	47%
Sikeston	MO	SPP EEI	100%
White Bluff	AR	SPP DENL	23%

Source: Based on geospatial analysis of S&P Global data.

Step 2: Hourly Generation

Most emitting, electric-generating units' hourly level data is reported to EPA's AMPD program.[25] This database provides the unit-level hourly level gross generation data used for this analysis.

Step 3: Hourly Revenues

SPP reports nodal and hub LMP data at the hourly level. These data were aligned to match the hourly generation data to estimate revenues. Revenues were calculated by multiplying the market price by a unit's generation in any given hour.

Step 3: Hourly Unit Costs

Unit costs were based on cost data reported by the company but aggregated by S&P Global. Included in dispatch costs were variable O&M per MWh, emission allowance cost (per MWh), and fuel costs.

[25] Air Markets Program Data (AMPD) is a publicly available dataset that includes current and historical data, 1995 to present, collected from power plants and other sources that report to EPA's Clean Air Markets Division under several market-based regulatory programs. It includes heat input, stack emissions, gross generation, and other data. For more information, see: https://ampd.epa.gov/ampd/.

For fuel cost, annual costs were spread evenly across all energy production, [*i.e.* annual fuel costs ($) ÷ annual gross generation (MWh)]. Hourly costs (per MWh) were then multiplied by generation (MW) in each hour to come up with hourly unit costs.

Table 4. List of Plants, owners, location, and operation costs (2-year average).

Unit Name	Primary Utility Owner(s)*	State	Variable O&M ($/MWh)	Fuel Costs ($/MWh)	Dispatch Cost ($/MWh)
Dolet Hills	Cleco and SWEPCO	LA	$ 3.51	$ 43.23	$ 46.74
H W Pirkey	SWEPCO	TX	$ 2.14	$ 31.74	$ 33.89
Hugo	Western Farmers Electric Coop	OK	$ 2.93	$ 22.56	$ 25.50
Independence 1	Entergy and Arkansas Electric Coop	AR	$ 1.17	$ 25.71	$ 26.89
John Twitty 1	City of Springfield	MO	$ 3.48	$ 24.28	$ 27.76
John Twitty 2	City of Springfield	MO	$ 3.48	$ 23.38	$ 26.86
John W. Turk Jr.	SWEPCO	AR	$ 2.77	$ 20.14	$ 22.91
Lon D Wright 8	City of Fremont	NE	$ 6.67	$ 19.74	$ 26.41
Muskogee 5	OG&E	OK	$ 1.76	$ 24.00	$ 25.77
Muskogee 6	OG&E	OK	$ 1.76	$ 23.47	$ 25.23
Nearman Creek	City of Kansas City	KS	$ 4.58	$ 21.32	$ 25.90
Plum Point	EIF Plum Point, John Hancock Life Insurance, and MJMEUC	AR	$ 3.13	$ 19.66	$ 22.79
Sikeston	City of Sikeston	MO	$ 2.91	$ 20.76	$ 23.67
White Bluff 2	Entergy and Arkansas Electric Coop	AR	$ 1.54	$ 25.13	$ 26.68

Source: S&P Global. *Owners whose share is less than 15 percent not shown.

Step 4: Hourly Net Energy Revenues (Losses)

For each hour of the year, hourly costs were subtracted from hourly revenues to calculate hourly energy net energy revenues (or losses).

Step 5: Cumulative Impact Assessment

Day-Ahead Nodal Price Results

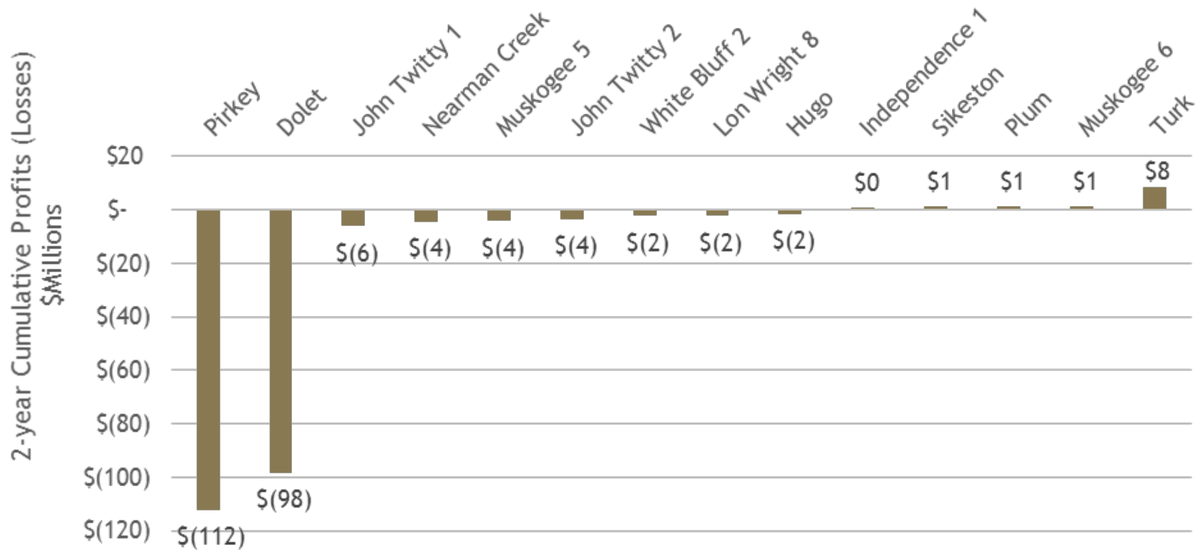
Units that self-commit are “price takers” in that the units take whatever the LMP clears at in any hour. Even those coal units that don’t self-commit may effectively function as price takers, in that coal units are generally inflexible and therefore unable to quickly respond to changes in demand by changing its output. Regardless, it is far more likely that the units identified by this analysis are getting all or nearly all of its revenues in the day-ahead market, as opposed to the real-time market.

If a plant is bidding in at its variable cost, clearing the market, and operating, then the LMP should cover at least the variable cost of that unit. Units that operate in the market shouldn’t be losing money, particularly with the availability of make-whole payments. If everything is operating as expected, then nodal price should be equal to or greater than variable cost of a coal unit that is operating in that node.

High-Resolution Results

The high-resolution analysis reveals that most of the units are either substantially uneconomic over long periods of time or operating uneconomically for periods of time and barely able to break even at the end of the year. Figure 5 displays the summary of all the units analyzed and those unit's cumulative net energy revenues (or losses) over a 2-year period. Of the 15 units analyzed, nine were so uneconomic over a 2-year period that the units weren't able to cover their variable costs, let alone the capital costs. For these coal units, the operators could have saved customers money by not operating at all. These results, however, only tell part of the story. All of the units that appear economic on a cumulative basis were nevertheless operating uneconomically for months at time.

Figure 5. Summary of Cumulative Results (1/2/2015-1/1/2017)

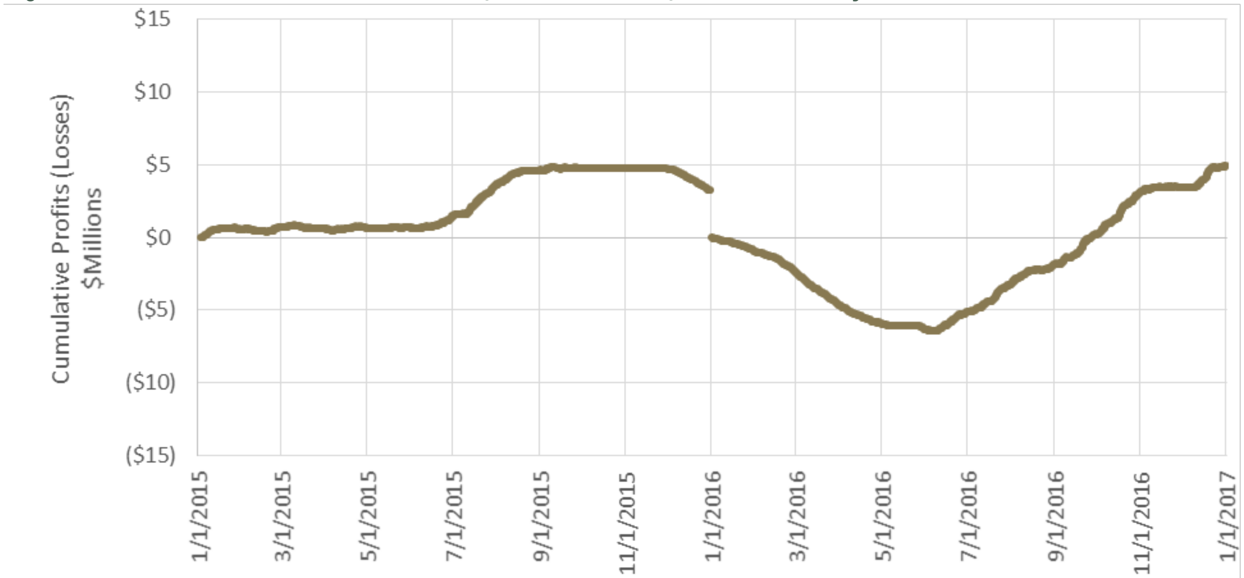


Source: Author's calculations

Within this high-resolution analysis, the Turk plant appears to be operating the most economically; however, such a conclusion would be specious. Our analysis shows that while Turk netted $3 million in energy market revenues in 2015 and $5 million in 2016 (for a net cumulative gain of $8 million dollars over 2 years), it operated at an $8 million dollar loss between December 2015 and June 2016. The unit wasn't operating in November of that year and when the unit turned on in December, it did so when the energy market price was below that unit's marginal cost and with most projections of market prices remaining low. The unit objectively should have never turned on. Eventually, those losses were offset but the operational decisions of the unit do not mimic that of a "rational actor." At the end of the study period, Turk's operators burdened its ratepayers with $8 million of unnecessary costs.

Figure 6 shows the cumulative cash flow, with the cash flow being reset at the start of 2016. For much of 2015, Turk operated in an operationally break even mode, having made a bit of money in the early part of the year and then losing some and gaining it back. The net result was that the cumulative earnings for the first six months of the year were marginally positive (ignoring fixed costs). The bulk of the 2015 earnings (again, ignoring fixed costs) were actually made in a two-month period, between 7/1/2015 and 9/1/2015. By October, the unit was no longer operating, possibly down for maintenance. In December, when the unit was turned back on, it was consistently losing money, eroding the $5 million dollars of cumulative earnings from earlier in the year, down to $3 million. The graph then resets for 2016, where it shows that for the first six months of the year the unit consistently operated at a loss. Perhaps if the unit was making money some days and losing other days, as it was the first half of the year prior, one could argue to keep it operating, however, the unit was consistently operating at a loss day after day, and month after month.

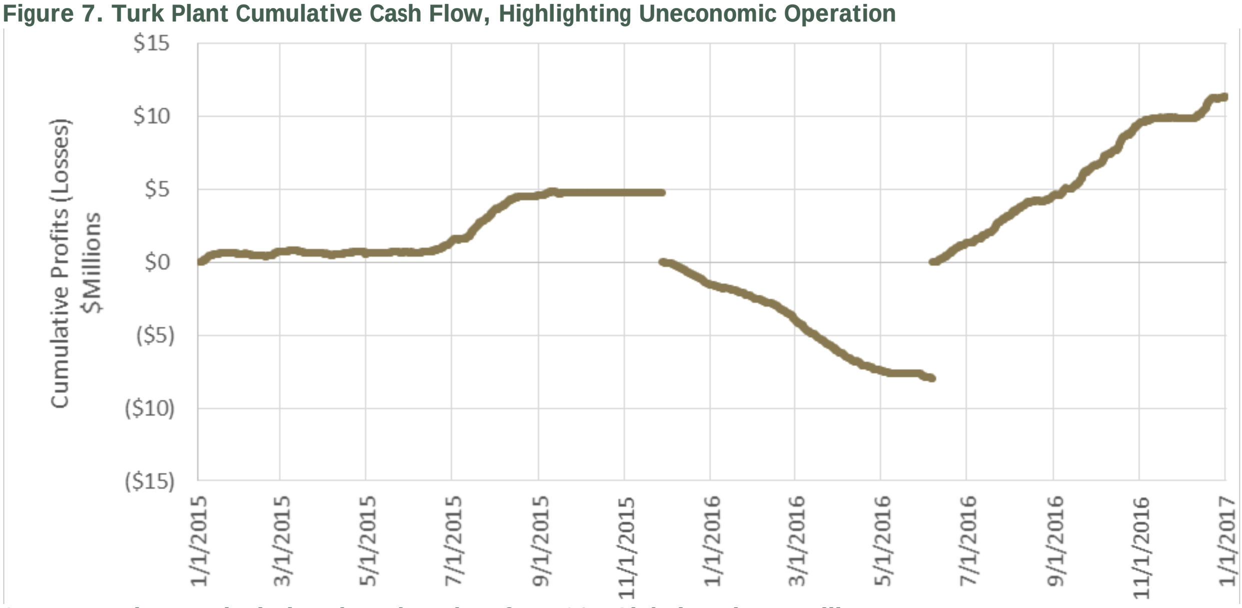
Figure 6. Turk Plant Cumulative Cash Flow, 2015 and 2016, Based on Hourly Data



Source: Author's calculations

Figure 7 highlights the periods of time when Turk operated economically and when it operated uneconomically.

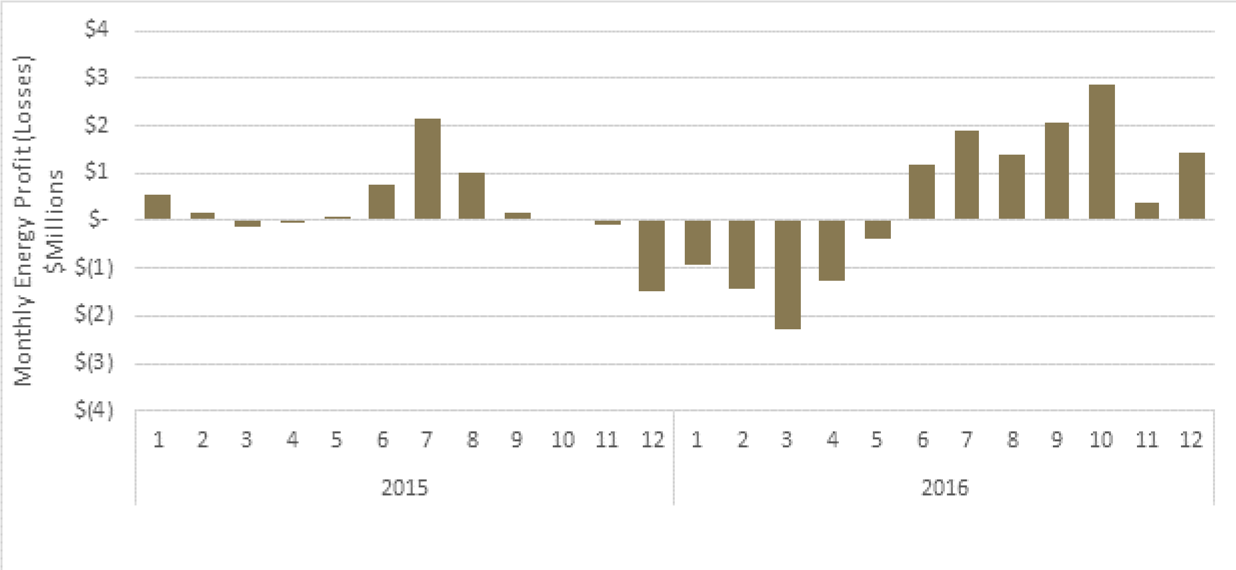
Figure 7. Turk Plant Cumulative Cash Flow, Highlighting Uneconomic Operation



Source: Author's calculations based on data from S&P Global Market Intelligence

This display of the results highlights that while Turk might have appeared to have made $8 million dollars, it was in fact losing even more money due to poor, irrational operational decisions. In effect, Turk's operational decisions didn't make $8 million, but rather lost $8 million in potential revenues. As shown in Figure 8. There were four other units that also appeared economic on an annual basis but a more detailed review, looking at a monthly granularity, reveals that all of them operated uneconomically for seven to nine consecutive months.

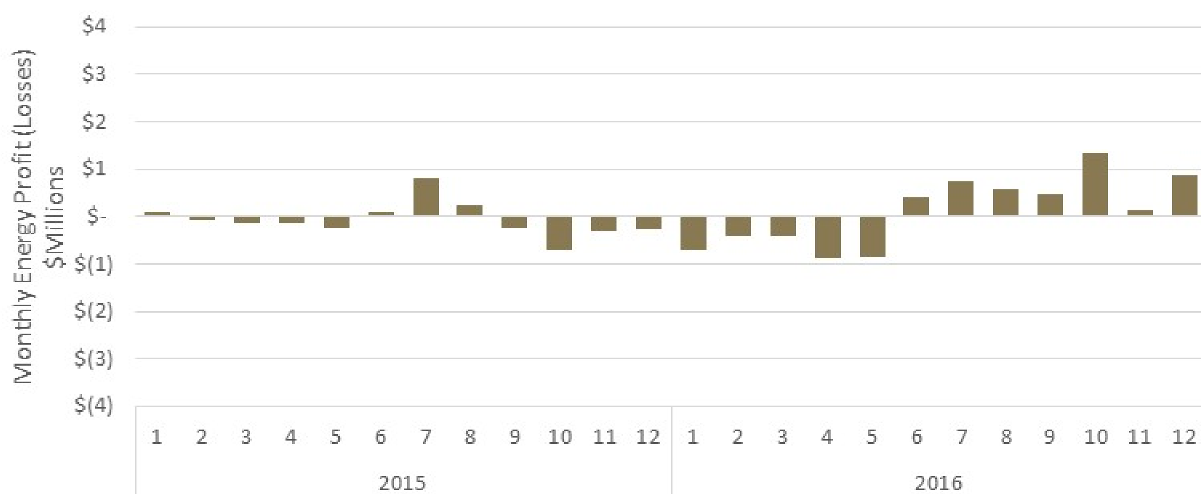
Figure 8. Turk Plant Monthly Cash Flow, 2015 and 2016



Source: Calculations based on data provided by S&P Global Market Intelligence

Independence's energy market revenues netted energy production costs by less than $1 million over the 2-year study period but over that same time period operated uneconomically for nine consecutive months.

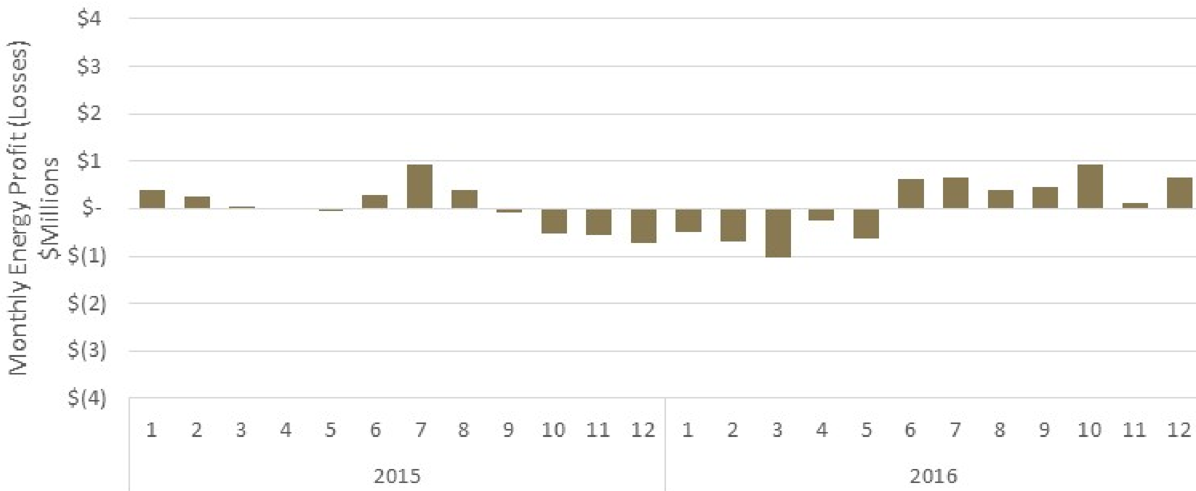
Figure 9. Independence Monthly Cash Flow, 2015 and 2016



Source: Calculations based on data provided by S&P Global Market Intelligence

Sikeston's energy market revenues netted energy production costs by about $1 million over the 2-year study period, but over that same time period operated uneconomically for nine consecutive months.

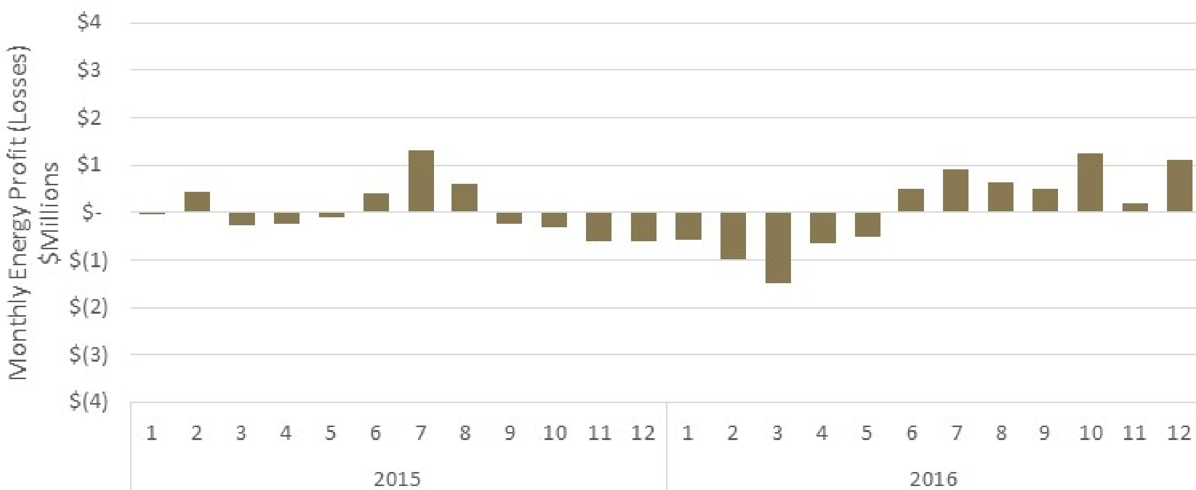
Figure 10. Sikeston Monthly Cash Flow, 2015 and 2016



Source: Calculations based on data provided by S&P Global Market Intelligence

Plum point's energy market revenues netted energy production costs by about $1 million over the 2-year study period, but over that same time period operated uneconomically for as many as nine consecutive months.

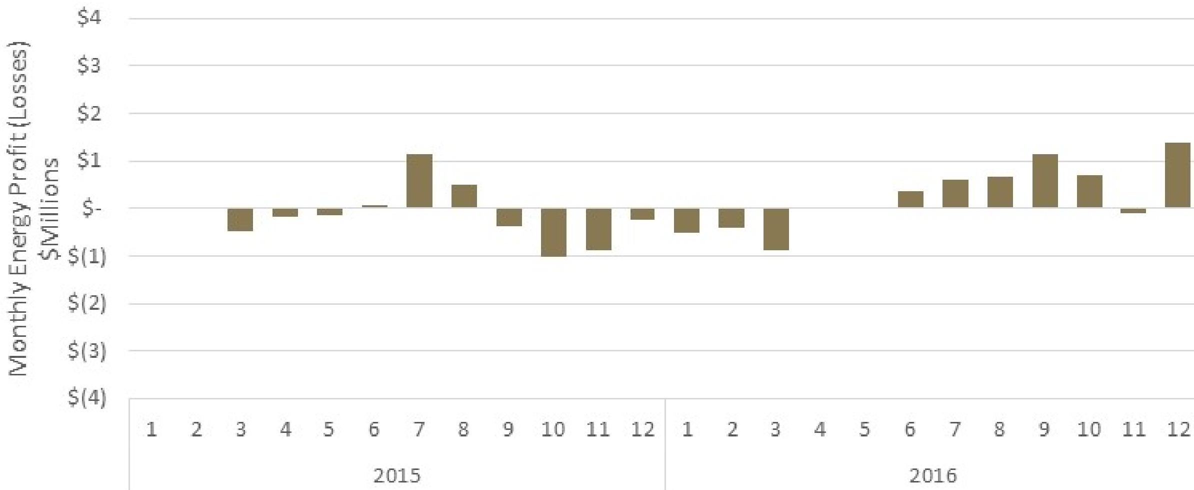
Figure 11. Plum Point Monthly Cash Flow, 2015 and 2016



Source: Calculations based on data provided by S&P Global Market Intelligence

Muskogee unit 6's energy market revenues netted energy production costs by about $1 million over the 2-year study period, but over that same time period operated uneconomically for seven consecutive months.

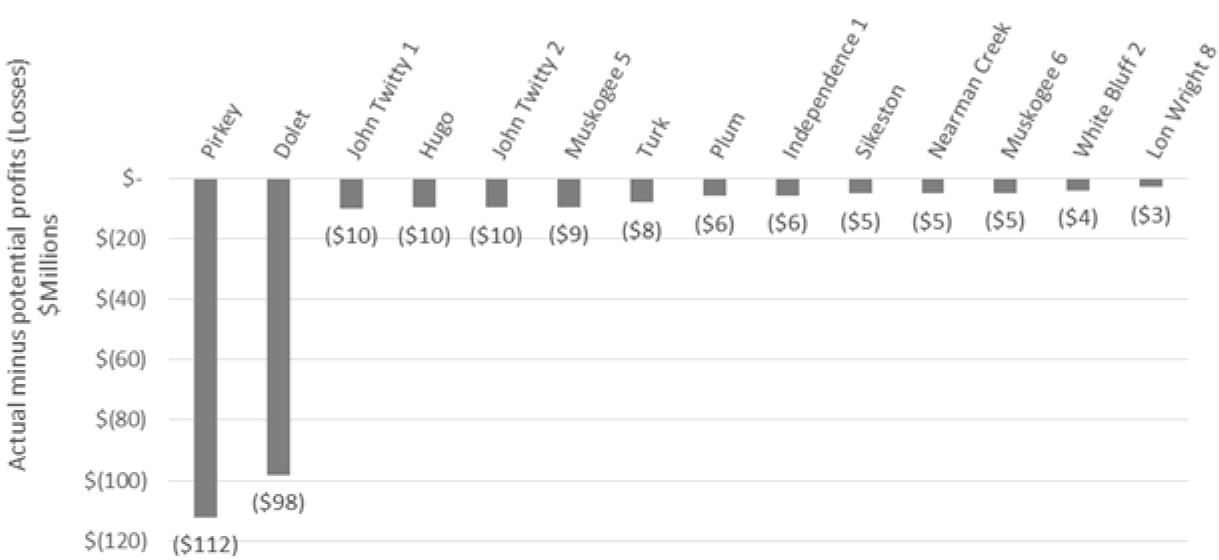
Figure 12. Muskogee 6 Monthly Cash Flow, 2015 and 2016



Source: Calculations based on data provided by S&P Global Market Intelligence

Below, Figure 13 shows the actual net energy revenues minus the potential net energy revenues of each unit. This calculation was based on looking at monthly net revenues, with revenues calculated on an hourly basis over the course of a month, and costs based on monthly costs. So, if a coal unit operated where it only lost money in a few hours of the day, those losses aren't counted as a "burden" to ratepayers. However, if a coal units net energy production revenues were negative at the end of the month, then those losses are counted as a ratepayer burden.

Figure 13. Ratepayer benefit (burden) from uneconomic dispatch



Source: Author's calculations based on data from S&P Global Market Intelligence

The Turk plant wasn't the only plant whose operator lost out by operating. All units analyzed had hundreds, sometimes thousands, of consecutive hours where nodal prices were below variable price, despite that unit being operated. Ignoring additional sources of revenue (like ancillary services) and other sources of costs (like fixed costs and debt), then each of these units was either losing money or losing out on an opportunity to make more money. Figure 9 shows each unit's actual net energy revenues minus the potential net energy revenues it could have saved customers money by not operating for long periods of time and simply buying energy from the market. For purposes of this analysis, we looked at monthly cash flow, and in any month where estimated costs exceeded calculated revenues, we assert that the plant could have not operated and saved customers money.

This analysis is highly suggestive that coal units within SPP are dispatching improperly. While there are a number of variables that even the high-resolution analysis doesn't account for,[26] the final conclusion is obvious: these units (and perhaps others) are operating in a sub-optimal fashion.

This analysis doesn't account for some of the operational constraints of coal-steam units, which cannot quickly turn on or shut down. This is why we didn't try to calculate every hour of the study period that a coal unit was uneconomic. However, as was the case with the Turk plant, rational actors shouldn't even consider starting up a unit with market prices below the marginal cost to operate the plant. The company should have been able to see the grim market outlook at the end of 2015 and simply waited until the market price came back to a level where it could make a profit with revenues from the SPP integrated power markets. The company's seeming indifference to profits when considering revenues from the SPP integrated market does not bode well, unless the company had a stream of income in parallel to SPP market revenues that it was relying on to keep its coal plants operating.

Hiding Fuel Costs as Fixed Costs

The high-resolution analysis does not conclusively identify units that are engaging in in uneconomic self-commitment. Rather, it identifies units that are engaging in uneconomic behavior, regardless of the cause. Self-commitment is the most likely cause; however, it is not the only possible cause. There is an additional, questionable, practice that might also explain these results for some of these coal plants.

Utilities might hide true variable costs by designating a portion of the fuel costs as a fixed cost. Utilities do this because the owners of coal-fired plants sometimes procure coal via long-term contracts with "liquidated damages" clauses. These so called "take or pay provisions" require the utility to pay a portion of the coal costs, even if the utility doesn't need any coal. If coal costs $5 per ton and the utility wants to buy 10,000 tons per month, then it may have to pay $50,000 per month regardless if it needs to burn coal. If a utility has to pay $50,000, or buy $50,000 in fuel, then the $50,000 is seen as a fixed cost. While based on reasonable economic theory, it distorts the company's internal accounting practices and leads to some perverse results. Take this hypothetical:

> A coal company is offered a discount on a large volume of coal with take-or-pay provisions, if the company burns all the fuel it would save money because of the discount. If the operator of a coal unit assumed that all the fuel costs were fixed then it would operate its unit at a high capacity factor. That high capacity factor might then be used to justify entering into another large volume take-or-pay contract, perpetuating the uneconomic cycle.

While the example is presented as a hypothetical, it is all too often what is actually happening. Sometime this practice is a result of a lack of sophistication in accounting or energy planning practices. Other times it is because there are structural reasons that actually incentivize this perverse practice. Some utilities are getting regulatory approval to own or contract with affiliated mining operations that lock in costs over long period of time at a fixed amount. This kind of treatment of fuel

[26] Including ancillary service revenues (which is likely a small portion of revenues) and fixed costs (which could be significant and would only make the coal units look less economic).

costs completely circumvents the intent of integrated energy markets, since utilities with captive customers can return back to state commissions to seek recovery on the “fixed” portion of the fuel costs.

While technically different from coal-self dispatch, the end effect is the same: units are operating at times when the energy market revenues are below energy production costs. While these unit’s operators may be able to rationalize the behavior using economic theory, if the end result is that the utility behavior doesn’t result in least-cost operations and is possibly costing customers tens of millions of dollars a year, then the utility should be reconsidering the practice. Like coal self-commitment, this practice results in an artificial market price suppression effect and costs customers money over the long run.

Who Pays for Uneconomic Coal Plants?

Why would a utility dispatch a coal plant during times when revenues from SPP integrated market for the electricity are insufficient to cover the costs to generate that electricity? This question is made even more important if those economic realities exist for months or years at a time. Wouldn't it make more sense to keep the plant idle, and only operate it when market prices are high enough to cover the costs of operation? Rational economic behavior would retire an uneconomic plant and replace the generation with more efficient and less expensive sources. When energy market revenues are rarely, or perhaps never, high enough over a long period of time to cover the variable costs to operate a power plant, those economics are a free market signal that a utility (or a competitor) would be best served building new and more efficient generation that can turn a profit at those levels of revenue. The existence of the SPP make-whole payment mechanism, furthermore, would seem to be an incentive for generation owners to operate in the market rather than to self-commit and operate at an apparent loss month after month, year after year.

Thirteen of the fourteen units that underwent the high-resolution analysis were owned by some combination of a state-regulated utility, a municipal utility, and/or an electric coop. These types of utilities all have captive customers. These customers happen to live in the service territory of one of the utilities and in order to receive power service they have to pay the utility based on a predetermined tariff. They have no choice but to accept the rates of that utility. For state-regulated utilities, that tariff is the end product of a public ratemaking process. Coops and municipal utilities also have predetermined rates for customers. In this report, we focus the following section on coal units owned or operated by state-regulated utilities, as well as municipal utilities and electric cooperatives. Broadly speaking, these three types of utilities recover costs directly from customers in a fairly similar process. Other owners of SPP coal units—for example, merchant coal plants sometimes sell largely or exclusively through purchase power agreements (PPAs)—therefore have access to non-market sources of revenue and could be engaged in self-dispatch. For example, this report identifies Plum Point, an IPP coal plant, as engaging in irrational market behavior; it has a contract to sell power to Cooperative Energy, Empire District Electric Company, Southwestern Electric Cooperative, and eight municipalities. These PPAs insulate Plum Point's ledger in a similar way that captive customers insulate regulated utilities, coops, and municipal utilities. While the remainder of this section focuses on traditional utilities the arguments and conclusions are equally applicable to other types of utilities.

Follow the Money

This analysis has identified several coal units in SPP that incur energy production costs that far exceed that unit's energy market revenues. This suggests that at least some utilities have identified a non-market source of revenue sufficient to cover variable costs, fixed costs, and make a profit. If true, this revenue is taking the form of a subsidy that is providing an operating incentive for otherwise uneconomic coal plants and is almost certainly distorting the integrated market with profound impacts to consumers and other SPP generators.

The participants in the SPP energy markets include generators that are state-regulated (part of commission-regulated utilities), as well as non-regulated generators like merchant operators. In the past, the commission-regulated utilities in the SPP states operated as vertically-integrated monopolies, as nearly all utilities had done for a century prior. The companies decided on its own when to dispatch its company-owned generating assets. The company's electric rates were regulated by a state or local commission, including the portion of the rates for electricity generation.

Now, many commission-regulated utilities are part of the SPP integrated market. This market creates a structure that in theory could be saving the captive customers of utilities significant costs for electricity. Captive customers that previously were strapped to utility-owned power plants, and whatever costs were incurred to operate those plants could today be paying for the least-cost electricity that could be reliably delivered to them, irrespective of who the ultimate owner of the power plant happened to be. A properly functioning integrated energy market should be providing all SPP electric consumers, including those served by regulated utilities, with least-cost electricity.

The function of state regulation of utility rates and rate cases at state commissions in the pre-market era was to provide an open and transparent opportunity for regulators and consumers to help ensure that electric rates and utility revenues were appropriate. Unfortunately, the purpose of state regulation and rate cases appears to have been perverted in some SPP states since the inception of the integrated SPP energy markets in mid-2014. Certain rate cases are potentially now being used by utilities to create a second stream of income that exists outside the SPP market to keep its own generating assets online, even when those assets are not the most economic sources of power in SPP, and to pass along the full costs for operating those plants to captured customers. The captured customers of utilities with uneconomic coal plants within SPP are losing out on the benefits the integrated market should be delivering.

Some utilities within SPP, unfortunately, appear to be going back to state commissions and using rate cases and other dockets to obtain ratepayer-funded subsidies for costs incurred in operating otherwise uneconomic coal plants. In the pre-market era, these utilities relied almost exclusively on commission approved rates as its source of revenue. Many independent power producers in today's SPP, by contrast, rely almost exclusively on the SPP integrated market as its source of revenue. State-regulated utilities within SPP, however, have created a hybrid structure. In that hybrid structure, these utilities collect SPP integrated market revenues for generating electricity, and then it goes to state commissions and via rate cases get approval to charge certain rates for electricity generation to captured customers. Embedded in those rates are the costs to keep apparently uneconomic coal plants running. It appears that state-mediated ratemaking is being used to make up the difference between SPP market revenues and variable operating costs at uneconomic coal plants for certain utilities.[27]

Non-market payments in the form of state-mediated ratemaking can function as backdoor subsidies for certain power plants. The payments might explain how coal plants whose operating costs–costs reported directly by the utilities themselves to entities such as the Energy Information Agency (EIA)–that are greater than the SPP market prices for electricity are nonetheless dispatching with high capacity factors month after month, year after year. The utilities that have a base of captured customers have the ability to take whatever revenues are being offered by SPP for electricity, knowing that the company will be made whole for electricity generation when it goes back to state commissions with the utility's captured customers bearing all the costs.

With the SPP integrated market, a new paradigm is in place and the decisions about which plants should be operating each hour of the day are supposed to sit with the neutral party, SPP, guided by the principle of generating the lowest-cost electricity for consumers. Rather than being strapped to the power plants owned by the utility that happens to serve its area, electricity customers within the SPP integrated market should be paying for the least-cost electricity that can be reliably delivered regardless of who owns the power plant. Unfortunately, it appears that this isn't happening across much of SPP. Utilities appear to be dispatching uneconomically, rather than letting the competitive market determine if the coal plants should operate. Regrettably, it appears that certain utilities within the SPP integrated market have engineered such a workaround to gain access to the backdoor subsidy.

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[27] Utilities would be guaranteed recovery of fixed capital costs plus a return (profit) regardless of where it sources its electricity.

Utilities should be purchasing electricity for its captive customers in the SPP integrated market (IM). The energy portion of the bill of any utility customer in SPP should only be the cumulative cost to purchase the kilowatt-hours from the IM and transmit them to the customer. If it turned out that a utility-owned generation asset bid into the IM, cleared the market, and was dispatched by SPP, then the utility customers would be getting lowest-cost power. Only in that structure can it be said that electric rates are truly lowest-cost, reasonable, and prudent.

It is possible that the wholesale operators of these coal units are not yet accustomed to the changing dynamics, opportunities created by energy markets like the SPP IM. Those overly faithful in markets and economics forget that inertia is a powerful force, and it may simply take time for companies to change their ways after decades of operation under a less competitive structure. In some states, distribution utilities aren't allowed to own generation assets. Even in states where such practices are allowed, there are many utilities that are "distribution only" utilities. While this structure doesn't eliminate concerns about affiliate transactions, it does begin to illustrate that utilities across the country are capable of supplying their customers with energy without being responsible for generating the electricity themselves. Many utilities sold the idea of joining energy markets as a way to benefit customers, by opening up access to lower-cost sources of energy. Markets often tout that it shifts risk away from customers and onto developers.

Consumer Impact

In a properly functioning market structure, utilities would offer resources to the market to be called on when it was economic and procure energy from the market in the lowest-cost possible way. This stands in stark contrast to what is currently observed in SPP, where a utility dispatching its coal units–via the self-commit behavior we have documented in this report–then passes on all the costs to operate those coal plants to its captured customers.

A utility could be purchasing the lowest-cost available power in SPP on behalf of its customers. The side of the utility that acts as load, that provides electricity and services to its customers, could have a structure of purchasing electricity on day-ahead and real-time markets to minimize costs to its customers, regardless of whether the electricity was generated by a power unit that the utility itself owns or a power unit that is owned by another entity. What is clearly most advantageous to customers is utility behavior that purchases electricity and services in a manner that is agnostic to the source of the power. This structure is clearly envisioned and codified, and is determined purely on cost. Utilities in many SPP states, where utilities have legal obligations to make economically prudent investments, provide the lowest-cost power, and avoid unnecessary and unreasonable expenses (or, at least, not pass such unreasonable costs on to ratepayers).[28]

The current practice of coal self-commit coupled with backdoor subsidies in state rate making appears to be saddling captive customers of certain utilities with higher-than-market costs for electricity, above and beyond the price that could have been obtained via the SPP IM. Our analysis shows that, over a two-year period, utility customers of just a handful of utilities paid nearly $300 million more than they needed to had the utilities behaved under a market paradigm rather than a self-supply paradigm.

[28] *See, e.g.*, 16 TAC § 25.231(b) (Texas law: "Only those expenses which are reasonable and necessary to provide service to the public shall be included in [a regulated utility's] allowable expenses"); *id.* § 25.236(d)(1)(a) (burden of proof is on the utility to show that "its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers"); *State v. Oklahoma Gas & Elec. Co.*, 536 P.2d 887, 891 (Okla. 1975) (confirming that Oklahoma statutory law, Okla. Stat. tit. 17, § 152, a public utility must "furnish adequate service to those it purports to serve, without unjust discrimination at the lowest reasonable rates consistent with the interests of the public and the utilities").

Coal plant owners with access to revenues outside the SPP IM will be able to sustainably dispatch a plant that an owner without access to those revenues would not be able to dispatch. As a result, the captured customers of utilities might be being denied billions of dollars of cost savings.

Consumers will not be protected in a market where a large portion of the electric generators are self-selecting when it wants to generate electricity and since many of generators can supplement whatever revenues it receives from the SPP IM with backdoor subsidies from state based rate making.

Market Impact

Imagine an energy market where all of the generating assets self-commit. It would be difficult to describe that system as a genuine market. In the SPP market, where nearly half of the resources are self-committing, how much of an energy market can SPP really be claiming to operate? When a utility self-commits its coal units, it is removing the ability of the SPP IM to control which units are producing power and ensuring least cost energy production—which is one of the principle objectives of the RTO. This report is hardly the first one to bring up the possible problems of coal self-commitment. The Market Monitoring Unit (MMU) is also assessing the high use of self-commitment status because of the limitations this commitment type places on the market.[29]

This analysis detailed that there were literally thousands of hours when coal units were operating uneconomically, and in each of those hours those coal units were depriving other market generators of revenues. Either those coal units shouldn't have been operating (and by necessity some other, less expensive, unit should have been operating), or that coal unit would have still operated, but would have set a higher clearing price. Either way, these units are siphoning off revenues from other market participants.

The production of electricity across SPP is a zero sum game, with only a precise amount of electricity needed every minute of every day. If self-committed coal units that are otherwise uneconomic but for the make whole payments are consuming large amounts of market share, then independent generators are being denied the ability to compete for a large amount of revenue. RTOs are supposed to create non-discriminatory rates, but allowing coal units to self-commit discriminates against those operators that don't have captive customers to fund a ratepayer subsidy. Moreover, it is discriminatory and unreasonable for the market to ask one subset of customers to pay above market costs while all other customers pay market costs.

The impact on the market is not limited to the current participants. The entire engine of the energy market is driven by the market signals set by LMP. Inefficient or expensive units drive up the LMP, sending a price signal for cheaper or more efficient units to enter the market. Coal units that are distorting that LMP are interfering with that cycle. An energy market cannot be expected to sustain itself if the basic principles of the market are not adhered to.

The consequence of these facts is that the SPP IM is possibly a market in name only. The impact of utility self-commit and underbidding energy offers within the SPP IM might be the most anti-competitive and anti-consumer behavior in any integrated electricity market anywhere in North America.

Regardless of the regulatory status of a utility or its assets, if the utility or utility shareholders were bearing the burden of the coal plants unable to compete in the SPP IM, the coal self-dispatch behavior would stop. A rational actor, absent out-of-market subsidies, wouldn't operate the way some of these units are operated. Some companies are coming to terms with this while others seem to be either stuck or in denial.

[29] SPP Market Monitoring Unit, "State of the Market Report 2016." Available online: https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf.

A Perverse Incentive Is a Bad Subsidy

The ratepayer funded, backdoor subsidy outlined above results in a perverse incentive: to operate expensive electric generating units more and cheaper units less. This is a bad subsidy on at least five fronts:

1. *Imperfect information*

"Perfect Information" is a requisite of perfect markets and requires all consumers and producers to know the price and value of products.[30] While truly perfect information is rarely obtained in markets, the fact that utilities are able to take advantage of regulatory loopholes is simultaneously exploiting and exacerbating existing imperfections. The dynamic exploits market imperfections because utilities are taking advantage of the hyper-technical and wonky aspects of rate-making and market rules, to force captive customers to subsidize their coal plants. No typical consumer could be expected to realize that they are supporting their utility's backdoor subsidy. Meanwhile, it exacerbates these imperfections because the LMP is the information provided by the market to the public. It serves as the price signal to encourage new entry and promote efficiency within existing participants. Bad actors thus artificially suppress the market clearing price, preventing the market from sending appropriate market signals.

2. *Inefficiency*

Most utilities aren't able to take advantage of this backdoor subsidy. All of the coal units identified in the high-resolution analysis are either regulated utilities with commission-approved, guaranteed rates they charge captive customers; or the coal units are independent power providers (IPPs) that have bilateral contracts to sell energy at a predetermined price. This analysis identified some of the units whose owners were/are taking advantage of this backdoor subsidy. It wasn't the lowest-cost, most efficient plants[31] that are receiving the subsidy. In fact, it was the opposite; it was the most expensive, least efficient plants that are being subsidized. These backdoor subsidies keep otherwise-uneconomic coal units online at the expense of other market competitors, sending revenues to less efficient and less economic generation that otherwise should have gone to competitors.

3. *Externalities, negative*

There are two types of externalities: negative externalities (which cause additional costs not reflected in price of the good or service) and positive externalities (which provide additional benefit or value not reflected in the price of the good or service).[32] Generally speaking, governments tend to tax or otherwise not incentivize goods that cause negative externalities, while subsidizing or otherwise encouraging goods that cause positive externalities; in a way subsidies exist to provide relief from negative externalities not exacerbate the problem.[33]

Pollution is the classic example of a negative externality.[34] Coal does not impose a positive externality, rather it the number one source of a major externality in the form of air and water pollution in the electric sector.[35] According to a 2010 study conducted by Clean Air Task Force, nine of the 12 coal plants that underwent the high-resolution analysis in this report were responsible for

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30 Pindyck and Rubinfeld, Microeconomics (7th ed.).

31 Generally, heat rate is used as an indication of efficiency of power plants.

32 Pindyck and Rubinfeld. Microeconomics, at 645.

33 Kolstad, Environmental Economics (7th ed.).

34 Pindyck and Rubinfeld, Microeconomics, at 645-669.

35 ELG weighted toxic exposure statistic. Coal is the number 1 contributor to mercury, sulfur, and nitrogen pollution.

239 deaths and 4,030.[36] The economic toll of these externalities, from these coal plants alone, was estimated to be over $110 million per year.[37]

4. Inequity (Economic)

The coal units identified in this analysis do not exclusively serve the operating utility's customers; however, only the captive customers of the utility end up paying the backdoor subsidy. This concentrates the costs onto a smaller pool of customers, rather than diluting those costs across the entire market.

5. Undemocratic and non-transparent

Subsidies are generally deliberate policy decisions that are proposed, scrutinized, and enacted by democratically elected representatives or their appointees, following a process of public comment, such that the subsidies—whatever their strengths and weaknesses—are at least the product of a transparent, intentional process, and those who put them in place are accountable for the subsidies' effects. But that's not what we have here. Regardless of whether the utility is self-dispatching or hiding fuel costs as fixed costs, the end result is that utilities are obstructing the true economics of its coal plants and receiving a subsidy that not by way of some intentional policy, but rather by exploiting loopholes and policies that don't explicitly forbid such practices.

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[36] Clean Air Task Force, "The Toll from Coal" (Sept. 2010). Available online: http://www.catf.us/resources/publications/files/The_Toll_from_Coal.pdf. Note: CATF only reported health impacts at the plant level, not the unit level.

[37] *Id.*

How Do We Solve This Problem?

In this report, we identify what we believe is a serious problem affecting the captured customers of certain utilities in SPP. Unless active steps are taken to address the problem of coal unit self-commit followed by non-market payments via state ratemaking, captured customers will continue to pay the cost to keep otherwise uneconomic coal plants running at a high level, and they will be denied the benefits of being part of an integrated energy market that operates on free market principles.

There are several operational and policy changes that could protect consumers from this kind of behavior by utilities.

What Can the Utilities Do?

Stop Doing It - Utilities are supposed to be providing their customers with least cost power while maintaining reliability. Dispatching uneconomically doesn't increase reliability but it doesn't prevent least-cost power from being procured. Some coal units in SPP are already participating in the market, rather than being self-committed. Coal plant operators have opted to change its dispatch paradigm for and that change is probably better for consumers. The fastest way to solve this problem would be for the utilities to solve it themselves.

What Can the Market Do?

Clearer Market Rules To Prevent Non-Competitive Bidding - Beyond utilities changing their behavior for the benefit of their captured customers and to comply with state requirements to provide lowest-cost power, SPP could require market participation in order to dispatch into the RTO and place reasonable requirements on the content of market bids. As a start, SPP could require that bids incorporate the entire cost of fuel and other variable operating and maintenance expenses. In the alternative, SPP could require that bids be consistent with lbs/MMBtu generation cost information submitted by the utilities to EIA. Either of these would eliminate the problem of self-commit and artificially low bids essentially guaranteeing that a utility-owned power unit will operate when it is otherwise uneconomic and uncompetitive.

SPP, Market Monitor, and FERC Intervention - Electricity production and consumption across the SPP RTO is largely a zero sum game. Power generators produce essentially as much electric power as consumers demand, not more and not less. Therefore, the electric power currently placed on the electric grid in SPP by self-committed coal plants is taking market share from other sources of electric power thereby preventing them from participating in and earning revenue from the market. Through their market authorities, SPP, the independent SPP Market Monitor, and/or FERC could take action to disallow bids by utilities at artificially low prices because of the detrimental effects on competition, if the utilities that provide those low price bids are able to obtain a second source of revenue and be made whole through state ratemaking.

What Can State Regulators Do?

State Commissions or FERC Could Disallow Recovery of Costs Imprudently Incurred - During rate cases, state commissions could disallow recovery of costs for fuel and variable operating and maintenance expenses that were incurred during periods of time when plants were voluntarily running uneconomically. Utilities have obligations to provide lowest-cost power, and customers should not be held to make a utility whole when it chooses to dispatch uneconomic coal plants. Thus, through existing rule making authorities, state commissions could, at least in practical effect, require utilities to offer utility-owned plants into the SPP energy markets with bids determined by fuel and variable operating and maintenance expenses--e.g., by declining to allow utilities to recover for fuel and other variable costs over and above the amount set by the SPP energy market, on the basis that such excess costs constitute unnecessary and unreasonable expenses as a matter of state utilities law. This would ensure that utility customers are paying for lowest-cost power.

Streamlined Rate Cases for Utilities in Integrated Energy Markets - Conceivably, during rate cases, the market revenues could be used by the state commissions to establish the caps to the level of revenues allowed to be collected by the utility from customers for electricity generation. Rate cases could be greatly simplified with this structure. No longer would parties and commission staff have to concern themselves with detailed accounting of fuel and other operating expenses. Instead, utility customers would be held liable for, and thus the utility allowed to charge, the cost of power at the closest node to the customer. A properly designed rate structure would not allow utilities to charge their customers more than that amount for electricity generation and revenues to the utility for electricity generation would be capped at that amount. Insofar as utilities are incurring expenses at utility-owned generation above market prices to deliver power to their customers from other (non-utility) plants, those above-market costs are imprudent and should not be borne by customers.

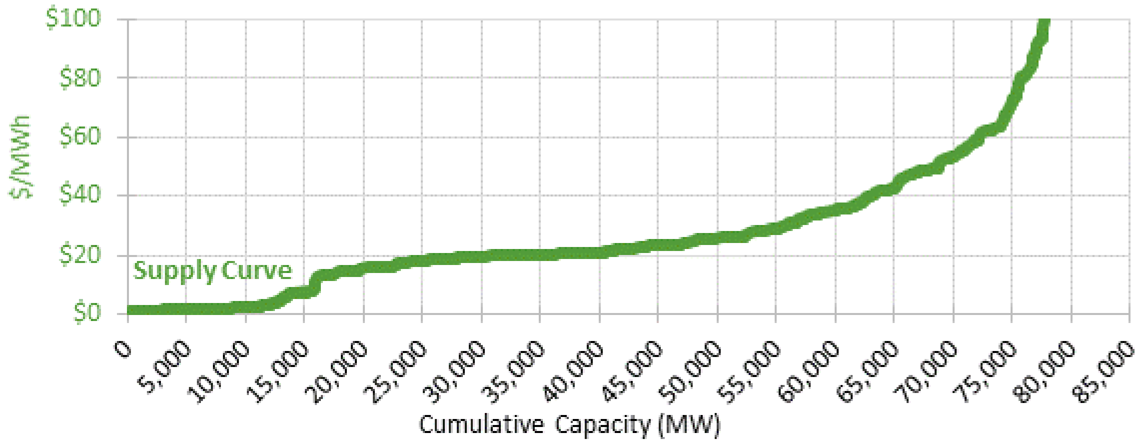
Appendix 1

Screening Test Methodology

Step 1: SPP Supply Curve

Using data from S&P Global, Inc., an industry standard energy data and news service, an SPP supply curve was created. That supply curve is illustrated in Figure 14. The supply curve was built by placing all the electric generating units in merit order, *i.e.*, in order of increasing dispatch cost.

Figure 14. SPP 2016 Supply Curve



Source: Data from S&P Global, author's calculations.

While "dispatch costs" are not explicitly reported, those costs should consist of a unit's variable costs—those generally associated with producing a unit of energy (i.e., production/marginal costs as opposed to fixed costs). Therefore, we calculated dispatch costs by combining fuel costs, variable O&M, and emission allowance costs (if applicable) for each unit. The owners of many of the EGUs report these costs in EIA form 923 or FERC form 1. The supply curve was then created by plotting the cumulative capacity obtained with the units ordered from lowest to highest dispatch cost.

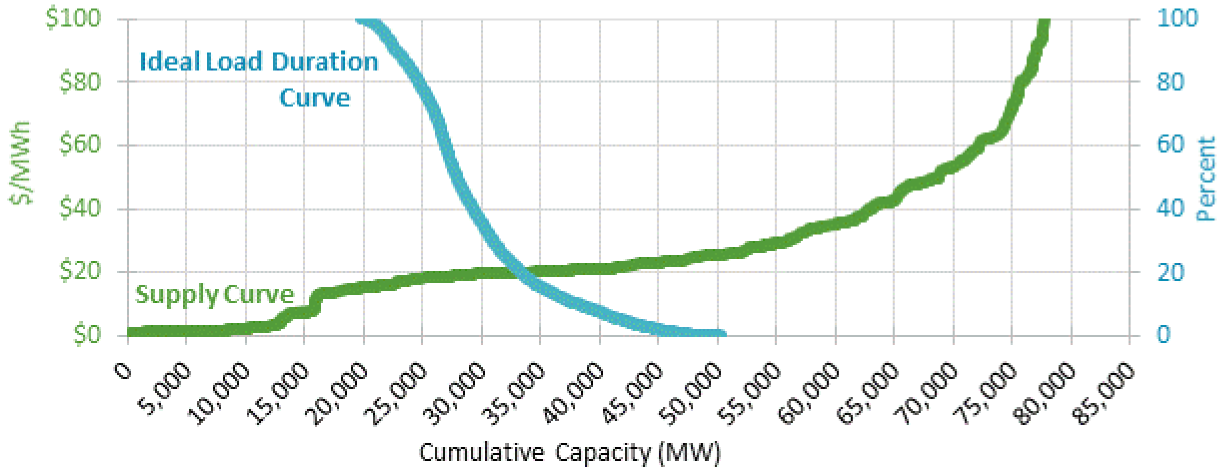
Step 2: Build Load Duration Curve

The cumulative electrical demand by consumers, known as load, was obtained for the SPP territory for each of the 8,760 hours in 2015. Load duration curves were prepared showing the percentage of the year that total load in SPP fell below a certain value. For example, the total load was below the peak load over 99% of the time, whereas the load may never have dropped below a certain floor even 1% of the time.

Figure 15 represents an "ideal" load duration curve. The ideal load duration curve can be thought of as an indicator of maximum capacity factor one might expect for a unit to operate given where it matches up on the supply curve. SPP's load was above 19.9GW in 100% of the hours, so one would expect the first 19.9GW of supply to operate at 100% of the time those units were available. Never did SPP's load exceed 50.3 GW, so one would expect any generators whose operating costs put them above the most expensive 50.3 GW of available generation to run very little or not at all.[38]

[38] Unit summer rated capacity was used to build out the supply curve so that the peak load in the load duration curve matched up with resource contribution to peak. All adjustments and values are based on summer rated capacity. Switching to nameplate capacity, then adjusting the load duration curve based on nameplate capacity in Step 3, had no material impact on individual units relative ranking.

Figure 15. 2015 SPP Supply Curve with Ideal Load Duration Curve



Source: Data from S&P Global, author's calculations.

Step 3: Adjust Load Duration Curve with Upper Bound Expected Capacity Factor

For legitimate reasons, some units operate more or less often than the ideal curve might predict. One such reason is the variable nature of wind, solar, and hydro resources, that are dependent on environmental factors like wind speed or river water flow. In addition, it is inefficient and sometimes not possible to serve load in one area with generation located in another because of constraints on the transmission system. Moreover, steam plants (whether powered by coal, nuclear, or gas) are generally less flexible than other types of generation and have a hard time following short-term changes in load. An increasing number of such coal plants are being taken offline on a seasonal basis in some markets, rather than trying to stay operational at times of the year that require more responsive and flexible generation. Operators in ERCOT, SPP's market neighbor to the south, have already begun designating some of its coal units as seasonal operators, including units at the Martin Lake,[39] Monticello, [40] and Gibbons Creek[41] generating stations.

To account for these various operational constraints, an adjusted load duration curve was created.

16 GW of hydro, wind and solar resources were in operation during the 2015 study period.[42] The adjusted load duration curve can be thought of as an "upper bound" of the generation in SPP over an annual or longer period of time. During shorter time durations, from minutes to a month or two, generation can exceed the adjusted load duration curve and sit somewhere in between the adjusted and ideal load duration curves. This will happen during times with above average winds, strong solar insolation, and during peak river flows in areas with hydro power plants.

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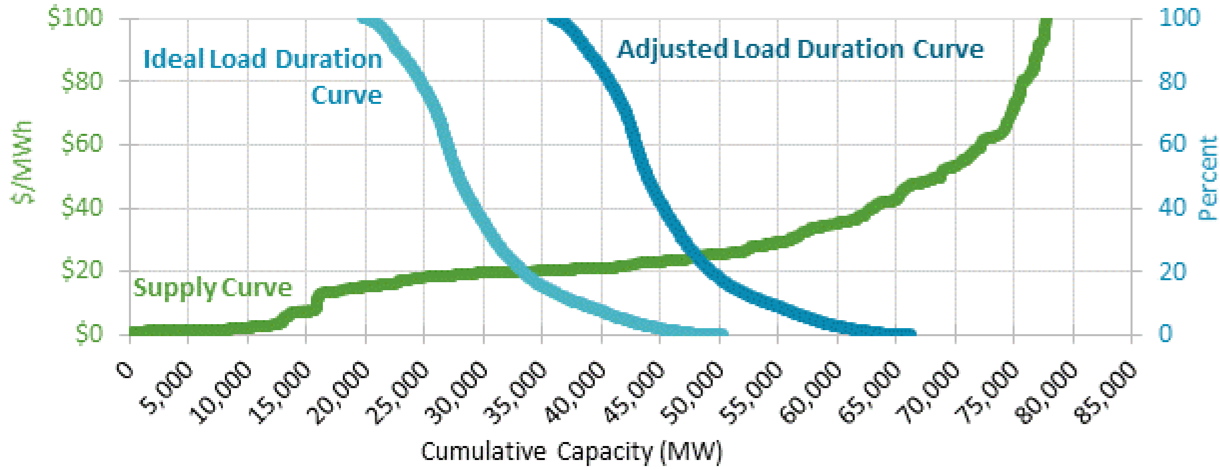
39 Barry Cassell, "Luminant switches a second unit at the Martin Lake coal plant into seasonal operations" (July 24, 2015). Available online: http://generationhub.com/2015/07/24/luminant-switches-a-second-unit-at-the-martin-lake.

40 *Id.*

41 Bryan Texas Utilities, "Gibbons Creek Power Plant to Begin Seasonal Operations" (July 21, 2017). Available online: http://www.btutilities.com/gibbons-creek-power-plant-to-begin-seasonal-operations/.

42 Summer rated capacity; data from S&P Global.

Figure 16. **SPP Supply Curve with the Adjusted and Ideal Load Duration Curve**

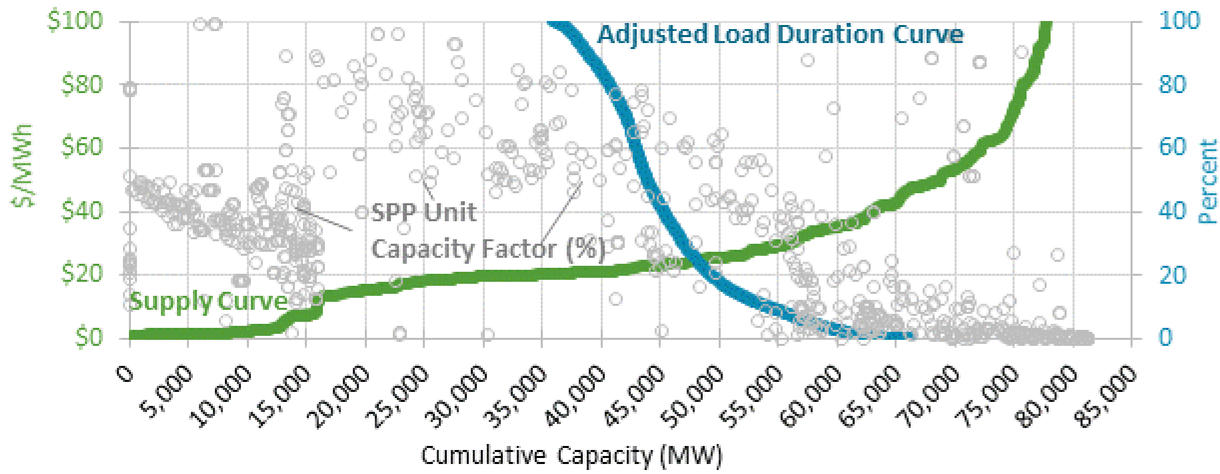


Source: Data from S&P Global, author's calculations.

Step 4: Capacity Factors

Each unit's annual 2015 capacity factor, an indication of the actual amount of generation produced during the year compared to the amount that was theoretically possible, is plotted as a dot directly above where that unit falls on the supply curve. Each grey dot represents the capacity factor (right-side vertical axis) of a SPP unit directly below it on the graph.

Figure 17. **SPP Supply Curve with Adjusted Load Duration Curve and Unit Capacity Factors Scatter Plot**



Source: Data from S&P Global, author's calculations.

Step 5: Capacity Factor Deviation

We compared each unit's actual annual 2015 capacity factor with its ideal load duration determined for this study. Units for which the actual capacity factor was greater than the ideal load duration operated more than the market would predict it should. Conversely, units where the actual capacity factor was less than the maximum expected capacity factor operated less than the market would predict it should. The difference between actual capacity factor and ideal load duration was designated as the "capacity factor deviation," with negative deviations being those where units operated more than expected and positive deviations those where units operated less than expected.

Figure 18 and Table 3 look at 4 hypothetical units, show where they would display on the screening analysis, and display those units' deviation value.

Figure 18.

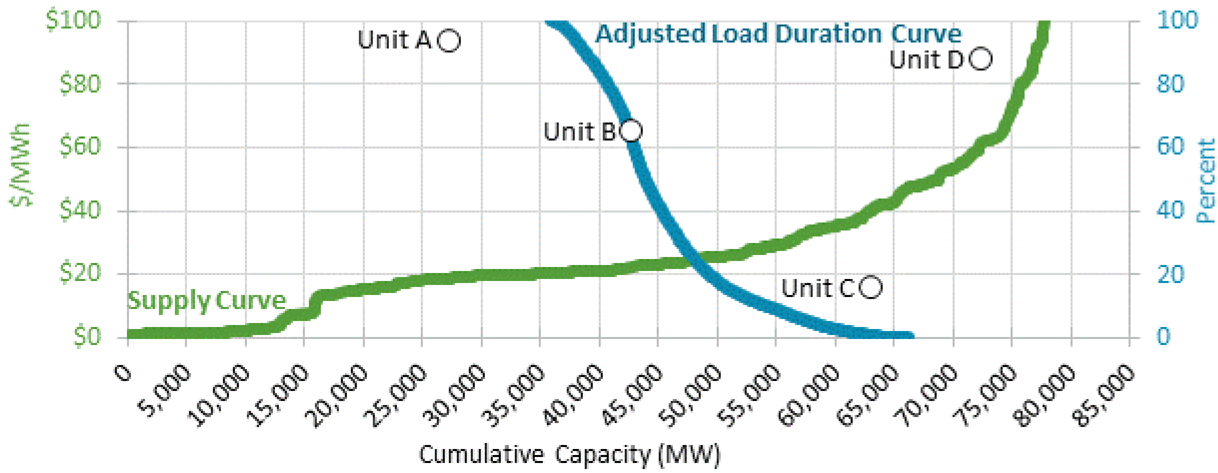


Table 3.

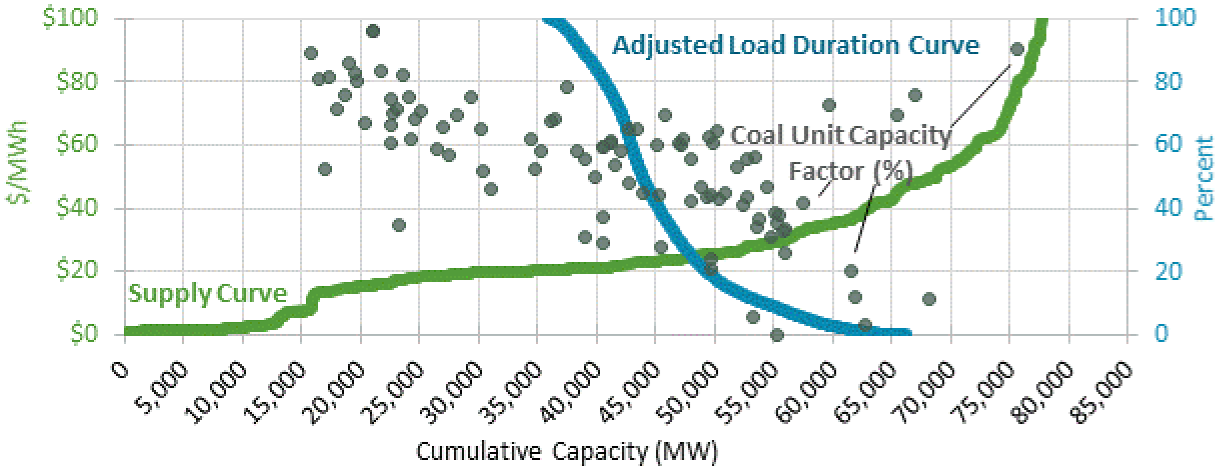
	Variable Cost	Capacity Factor	Expected CF	Deviation
Unit A	$19	95%	100%	5%
Unit B	$22	65%	65%	0%
Unit C	$40	18%	3%	-15%
Unit D	$63	87%	0%	-87%

After determining the capacity factor deviations for each unit in SPP, the units were grouped into one of four categories, with category 1 being the units being operated far more frequently than expected by economics, and category 4 units operating far less frequently than expected by economics. The remainder of this analysis focuses on Category 1 and Category 2 anomalies.

Screening Test Results for Coal Units

The only fuel SPP specifically divides out by market versus self-commitment is coal; as a result, the analysis pulls out the coal units to identify which of those units are possibly dispatching in such a fashion that would interfere with the market.

Figure 19. Coal units (gray dots) displayed on graph of supply curve and adjusted load duration curve



Source: Data from S&P Global, author's calculations.

In order to rank each coal unit on a scale, each unit was given a score based on the difference between expected value and actual value. If a unit's expected capacity factor was far below its actual capacity factor we excluded it from Table 4.

Table 4. Results of Screening Analysis
a

Plant Name	*Unit No*	Capacity Factor (%)	Expected Capacity Factor (%)	Expected vs Actual
Scottsbluff ST Plant	SCBF	90	0	-90
Dolet Hills	1	76	0	-76
Pirkey	1	73	3	-70
Trigen-Kansas City	1	69	0	-69
Hugo	1	64	17	-47
John Twitty Energy Center (Southwest Power)	ST2	56	11	-46
Archer Daniels Midland - Columbus	GEN1	55	12	-43
Asbury	1	62	19	-43
Tecumseh	7	61	18	-42
Muskogee	5	53	14	-39
Grand River Energy Center (GRDA)	1	47	10	-37
Lon Wright	7	42	6	-36
Sikeston	1	62	28	-34
Plum Point Energy	STG1	69	37	-32
White Bluff	2	44	12	-32
Nearman Creek	1	60	29	-31
John W. Turk, Jr. UPC	1	61	30	-31
Tecumseh	8	55	25	-30
Muskogee	6	45	15	-30
Independence	1	38	8	-30
Lon Wright	8	41	12	-29
Montrose	2	35	9	-27
White Bluff	1	43	17	-26
Oklaunion	1	37	10	-26
Lon Wright	6	33	8	-26
R.S. Nelson	6	44	19	-25
Independence	2	33	8	-25
Welsh	1	44	20	-24
Montrose	3	34	11	-23
John Twitty Energy Center (Southwest Power)	ST1	31	9	-22
Sheldon	1	60	41	-19
James River Power Station	4	20	2	-19
Welsh	3	42	25	-17
Sooner	1	65	54	-11
James River Power Station	5	12	1	-10
Sibley	1	24	19	-5
Sheldon	2	44	40	-4
La Cygne	2	65	63	-2
Marshall, MO	5	3	1	-2
Sibley	2	21	19	-2

Source: Author’s calculations, based on data from S&P Global

Screening Analysis Conclusions

The screening analysis flagged a number of units in SPP as operating significantly more than would be predicted by the economics within SPP alone. 20 units, in fact, appeared to operate at least 30 percentage points more than its calculated expected value give operating costs and typical loads within SPP.

It is important to recognize that these initial results do not account for every operational issue that might be at play and impact dispatch decisions within SPP. At the screening analysis level, for example, we lacked data to account for two relevant issues. First, the analysis is performed at the ISO level of spatial granularity and therefore doesn't account for key locational differences within the ISO. Within SPP there are transmission constraints which would drive up locational marginal price at certain nodes and might explain why two units with similar operating costs might operate with different temporal frequency. Other explanations might include operational constraints of a given unit.[43] Second, because this analysis was conducted looking at annual results, it also doesn't account for short-term fluctuations in coal fuel price, though we do not expect those fluctuations to have a measurable impacts on day-to-day dispatch decisions for coal-fired units. Gas prices change enough on a daily, and even hourly, basis to affect gas-fired units' dispatch discussions, but coal fuel prices tend to be less volatile, with little price fluctuation even on a monthly basis, and many utilities secure year- and multiyear-fuel coal supply contracts. To address these potential shortcomings, we developed a higher resolution analysis (described below).

Even if a unit that was identified as operating more often than expected was operating in a load pocket or transmission constrained area, one would expect there to be an economic driver for a market solution, a new transmission line, for example. Some experts place trust in these so-called self-correcting solutions, though they seem to have been ineffective at solving the problem. This is because self-commitment of coal resources depresses market prices (since those generators can take a loss on energy market revenues due to subsidization by retail ratepayers), energy market prices don't rise as they would otherwise be expected to, which inhibits the market from incentivizing the entry of new resources like wind or energy efficiency, or a new transmission line being constructed to better bring in power from other generators. The market is, after all, designed to send a price signal to encourage new, more cost-effective participants to drive down prices. This is often referred to as a market self-correcting.

[43] Operational constraints might include ramp-up or ramp-down time—which is the time it takes for individual electric generating units to increase or decrease its output. It might also include minimum up time or minimum down time—which is the length of time a unit must remain operating (or not operating). For coal generators, these operational constraints exist because of the physical limitations of the units. Coal-fired power plants burn coal to heat up water, create steam, and rotate a turbine that generates electricity. A boiling pot of water doesn't instantaneously start/stop boiling right after the heat source is turned on/off. Similarly, coal plants must heat up and cool off.