MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

IN THE MATTER OF AN INVESTIGATION OF MISSOURI JURISDICTIONAL GENERATOR SELF-COMMITMENTS INTO SPP AND MISO DAY-AHEAD ENERGY MARKETS

FILE NO. EW-2019-0370

File No. EW-2020-0032 – Staff's Analysis of Ameren Missouri;

File No. EW-2020-0033 – Staff's Analysis of Kansas City Power & Light Company;

File No. EW-2020-0034 – Staff's Analysis of KCP&L Greater Missouri Operations Company;

File No. EW-2020-0035 – Staff's Analysis of The Empire District Electric Company.

AUGUST 23, 2019

*** Denotes Highly Confidential Information ***

Introduction:

On June 5, 2019, the Missouri Public Service Commission ("Commission") issued an *Order Opening an Investigation of Missouri Jurisdictional Generator Self-Commitments and Self-Scheduling* ("Investigation Order"). In its order, the Commission stated,

> Both Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) operate day ahead energy markets designed to identify the supply of electric generation required to meet demand, and select demand-side and supply-side resources for dispatch in a manner designed to minimize overall costs to the system while meeting reliability requirements. However, in some circumstances, a market participant may choose to self-commit a particular supply-side resource for dispatch and self-schedule that supply-side resource's output and accept whatever market price results rather than awaiting market commitment and dispatch by the Regional Transmission Organization (RTO). (footnote omitted).

The Commission directed Staff to investigate the self-commit and self-scheduling practices of Missouri's investor-owned electric utilities ("IOU") to determine if such practices inure to the benefit of their ratepayers.[1]

The Commission, in its Investigation Order, requested each IOU submit, for each of its generation facilities, information on a monthly and annual basis over the last three years. Specifically, the Commission requested: 1) whether the utility has full control, minority partial ownership or has a power purchase interest in the capacity of each resource; 2) the nameplate capacity; 3) the amount of net and gross energy generated for each facility; 4) the amount of energy bid into the day ahead market and the amount that cleared; 5) the amount of energy self-committed, self-scheduled and market selected; and 6) the difference between production costs and corresponding prevailing market prices for energy self-committed.

Staff supplemented the Commission's request with additional parameters, submitting a spreadsheet (See Attachment A) to each IOU for consistency in responses. The IOUs, Sierra Club and APA-CGA provided written comments in response to the Commission's Investigation Order. In addition, Staff had several conversations with other interested stakeholders.

As a part of their response to the Commission's request for information and despite Staff's efforts for consistency, each of the four IOUs provided slightly different data based on the IOU's method of record keeping. Staff determined it was most appropriate to evaluate the data

[1] EW-2019-0370, "Order Opening An Investigation of Missouri Jurisdictional Generator Self-Commitments and Self-Scheduling".

for coal-fired power plants due to: the propensity of coal-fired power plants to be designed and operated as base-load units, operational characteristics, and the reasons for other types of plants being self-committed being primarily testing related. In Staff's opinion, this approach will provide the Commission with the most consistent and comparable analysis for each utility.[2]

Staff's Report generally documents Staff's analysis and conclusions based on the information provided by Ameren Missouri, The Empire District Electric Company ("Empire"), Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations Company ("GMO"), MISO and/or the MISO Independent Market Monitor ("MISO-IMM"), SPP and/or the SPP Independent Market Monitor ("SPP-IMM"), Advanced Power Alliance and Clean Grid Alliance (collectively, "APA-CGA") and Sierra Club.

The Highly Confidential, Confidential, and public results of Staff's analysis for each individual utility will be filed as an Appendix, with associated Staff company-specific Schedules, to this Report in the associated docket assigned to that utility. Ameren Missouri's report will be filed in File No. EW-2020-0032, KCP&L's report will be filed in File No. EW-2020-0033, GMO's report will be filed in File No. EW-2020-0034 and Empire's report will be filed in File No. EW-2020-0035.

Based on Staff's analysis of the information provided and to the extent the generating units are operating at a profit, Staff has not found any evidence that customers are being actively harmed by the IOU's market strategy regarding self-committing units since revenues seem to exceed costs and should subsequently flow through the FAC – Rider tariff. However, Staff recognizes the limitations on its ability to analyze data and understands that other stakeholders raise concerns as to the level of data provided and transparency of that data; therefore, Staff plans to monitor the number of hours that units are dispatched at their economic minimum under self-scheduled or must-run status without any additional dispatch under the economic or market status in future prudence reviews.

[2] It should be noted that in written comments and Staff's conversations with stakeholders, the focus was also on coal-fired units.

Definitions:

Staff provides the following definitions for consistency in the reader's understanding of this Report:

- Unit *commitment* is the decision to bring a unit online (or to subsequently take the unit off-line (i.e., to decommit it)). In contrast, unit *dispatch* establishes the level of output for a unit once it has been committed.
  - There are five commitment status designations in the MISO market, as follows: (i) economic, (ii) must-run (a/k/a, self-commit), (iii) outage, (iv) emergency, and (v) not participating.
  - There are five dispatch status designations in the MISO market, as follows: (i) economic, (ii) self-schedule, (iii) emergency, (iv) not qualified (this status only applies to ancillary services), and (v) not participating.[3]
  - There are five commitment status designations in the SPP market, as follows: (i) Market, (ii) Self (a/k/a, self-commit), (iii) outage, (iv) reliability, and (v) not participating.[4]

- Must run (self-commit) commit status designates that the market participant ("MP") itself is committing the resource at its unit minimum. However, its dispatch above its unit minimum is determined by MISO, based on price. An economic commit status means that it is MISO that determines whether to commit the unit.[5] SPP operates in a similar fashion.[6]

  For example, a hypothetical power plant has a minimum generation level of 250 megawatts ("MW") and a maximum generation level of 500 MW. A utility could self-commit that power plant at the minimum level of 250 MW. At that point the power plant would be brought online and would be contributing 250 MW of generation into

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[3] Ameren Missouri's Response to order opening an investigation of Missouri Jurisdictional Generator Self-Commitments and Self Scheduling and to order Directing Comments, Pg. 2.

[4] Market Protocols SPP Integrated Marketplace Revision 40 Section 4.2.2.2.1.

[5] Ameren Missouri's Response to order opening an investigation of Missouri Jurisdictional Generator Self-Commitments and Self Scheduling and to order Directing Comments, Pg. 2.

[6] Market Protocols SPP Integrated Marketplace Revision 40 Section 4.2.2.2.

the market. If the generation needs of the market changed, the market operator could request the power plant be dispatched to a generation level greater than 250 MW and up to the maximum generation level of 500 MW. Due to the self-commit status of the power plant, the market operator would not be able to dispatch it to a generation level less than 250 MW. However if the same power plant were to self-commit 250 MW and designate the remaining 250 MW as economic dispatch (market for SPP), the unit would remain dispatched at its minimum generation level while retaining the flexibility to generate more electricity and resultant revenue as the market generation needs and price points dictate.

- Startup costs are the operational and maintenance costs along with the cost of startup fuel that must be burned to bring a power plant online.
- Minimum run time is equal to the minimum number of hours that a power plant must run once it is committed with the market.
- A thermal cycle is the process that a power plant goes though as it comes online from a cold state or goes offline from a hot state. Such state changes induce pressure and temperature stresses on power plant equipment that can result in wear and damage.
- A power plant's heat rate is a measure of thermal efficiency and is typically given in units of BTU/kWh. The heat rate is equal to the amount of fuel energy being consumed by a power plant per unit of electrical energy being output. The higher a power plant's heat rate, the lower its efficiency.

Staff's Analysis:

Staff's task was to investigate whether the self-commit and self-scheduling practices of Missouri's investor owned electric utilities benefit their ratepayers. In addition to the questions the Commission posed in its Investigation Order, Staff requested information from each IOU that could be broken down into three categories: hourly bid information, generator characteristics and load node information. The spreadsheet provided to the IOUs illustrating the data requested is included in Attachment A.

Staff reviewed the market bid information for consistency and identified any areas that changed abruptly. Staff analyzed the data to determine which coal plants were operating at a loss or turning a profit consistently. If a utility operates a plant at a loss for extended periods of time, customers would be harmed through additional costs recovered through the Fuel Adjustment Rates. Conversely, if a utility operates a plant in a manner that provides revenues in excess of the costs to operate, customers realize the benefit attributed to the Off-System Sales Revenue. Using the market bid information, Staff reviewed unit offer data, physical unit characteristics, and fuel prices. Staff also looked at Locational Marginal Prices ("LMP") in the day ahead ("DA") market. Using this information, Staff calculated a DA energy cost as well as a DA revenue amount at the DA cleared level of generation. The results of this analysis are contained in each IOU-specific docket.[7]

Staff also requested feedback on reasons IOUs might self-commit generating units. The IOUs indicated that some of the reasons they have or do self-commit a generating unit 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; overtime costs, increased major maintenance costs, compliance testing, vetting repairs; and a risk-averse business practice approach. Many of these reasons stem from the fact that the day ahead market model clears the next 24 hours.

Coal plants tend to have slow ramp rates, start-up times that are much longer than most natural gas units and tend to have equipment like air quality control systems, with large amounts of auxiliary equipment necessary for SO_2, NO_2, and mercury compliance, if applicable. This equipment may require testing.

Day ahead market model:

According to Ameren Missouri's response to the Commission's initial request in this case:

> There are days when a given unit would not clear in the MISO or SPP day-ahead market if offered as economic because the modeled margin between the LMP revenue and the as-offered cost for that unit is negative for that specific 24-hour period. However, making a unit commitment status decision merely by looking at one 24-hour period is not appropriate and would harm customers. This is because the MP must look past the next 24 hours and assess whether this one-day revenue shortfall is projected to persist for a prolonged period of time such that the cumulative

[7] Ameren Missouri's report will be filed in File No. EW-2020-0032, KCP&L's report will be filed in File No. EW-2020-0033, GMO's report will be filed in File No. EW-2020-0034 and Empire's report will be filed in File No. EW-2020-0035.

> shortfalls would exceed the total of the expected foregone margins, the cost to restart the unit and the risk of significant maintenance and capital expenses arising from cycling the unit if it is committed and then decommitted and then committed again. The MP must also account for unit downtime minimums which means that if a unit downtime minimum is for more than one day, de-committing the unit based only on the next day's MISO or SPP model results could mean that the unit will forego margins for the following days when it remains shut-down.[8]

In the 2018 State of the Market report, the SPP-IMM stated:

> In the current design, a resource that is required to run for multiple days is not evaluated by the day-ahead market to see if the resource is economic over its minimum run-time. The clearing engine may see that it is economic on the first day and issue the commitment, and then in future days the resource will stay on until its minimum run-time is met even if it is uneconomic. As such, many resources that have multi-day minimum run times avoid the market clearing process and instead self-commit in the market based not on an evaluation by the market, but on their own evaluation of market conditions.
>
> Adding multi-day unit commitment logic is at the top of the current SPP stakeholder market design initiative list and has been discussed in 2018 and 2019 in the stakeholder process. SPP staff has proposed a multi-part approach to address multi-day unit commitment. First, they have indicated that they prefer to provide a multi-day forecast of prices or schedules as it would be quicker, easier, and less expensive to implement. The multi-day forecast would serve to provide information to aid MPs that self-schedule to do so in periods that would be more favorable for their resources and for the market. Second, SPP staff has indicated that after the multi-day forecast was made available, they would consider developing a multi-day unit commitment process. The MMU [Market Monitoring Unit] is currently in the process of reviewing the SPP staff proposal to provide multi-day forecast information. At this time, it is not clear if the benefits of this approach outweigh costs and concerns.[9]

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[8] Ameren Missouri's Response to order opening an investigation of Missouri Jurisdictional Generator Self-Commitments and Self Scheduling and to order Directing Comments, Pg. 3.

[9] https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf, Pg. 243-244.

Increased maintenance costs:

Ameren Missouri stated:

> The impact on maintenance and capital costs resulting from increased forced outages, component failure, and shortened component life is significant. This is in addition to foregone market margins when units are out of service. Increased cycling is reasonably expected to result in increased turbine fouling which is a leading cause of unit derates. Correcting this condition can cost several million dollars during a two to three-month long outage period. The number of tube leaks experienced by a unit which is cycled frequently would also be expected to increase. As a conservative estimate, a tube leak outage can cost as much as $50,000 per day in repair costs. A shortening of the inspection intervals for generator field windings to approximately every five (5) years versus the current approximately ten (10) years is yet another expected result of frequent cycling. This is significant, since generator inspections can cost more than $1,000,000 and take over four weeks to perform. Components which are more vulnerable to damage as a result of more frequent cycling (e.g., condensers and feedwater heaters from thermal stresses or air heaters and precipitators from corrosion as air temperatures fall below the dew point when shut down) would be expected to fail or otherwise require service at more frequent intervals.[10]

Testing and vetting repairs:

KCP&L and KCPL GMO stated:

> Another key factor related to the self-commitment of resources is compliance testing. KCP&L is required by various governing bodies to regularly test resources for reasons such as emissions performance. KCP&L may have no choice but to self-commit a resource during these testing periods to ensure the resource is online and available to satisfy testing requirements.
>
> Lastly, KCP&L may sometimes self-commit a unit to vet repairs following an outage. If a resource performed a turbine overhaul they may want to check turbine vibration at both running speed and with load on the turbine. Many times, a contractor and specialty vibration equipment are on site so vetting that as soon as possible is ideal, rather than waiting for a potential market start and risk losing both the contractor and equipment to

[10] Ameren Missouri's Response to order opening an investigation of Missouri Jurisdictional Generator Self-Commitments and Self Scheduling and to order Directing Comments, Pg. 7.

> another job. Furthermore, this testing reduces the risk of being unreliable when needed for a market-commitment following a turbine overhaul because further tuning is needed the next time the unit start.[11]

Independent Market Monitor:

The SPP Independent Market Monitor discussed the topic of self-commitment in its 2018 State of the Market Report. The SPP-IMM stated:

> Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices. Some of the reasons for self-committing 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. Generation offers in the day-ahead market averaged almost 53 percent as "market" commitment status followed by "self-commit" status at 30 percent of the total capacity commitments for 2018. These levels almost exactly match those in 2017, however the overall trend is still downward, as 2016 had 48 percent as "market" commitment status, and 35 percent as "self-commit" status. While the overall increase in market commitments and decrease in self-commitments highlights an improvement, self-commitments still represent over 30 percent of generation, a trend that has existed since the Integrated Marketplace began in 2014. In order to improve market commitment in the SPP market, we recommend that SPP and stakeholders look to find ways to address this issue.[12]

In contrast, the MISO-IMM is largely hands off with respect to self-committing a plant. During a call with the MISO-IMM, the MISO-IMM indicated that market forces will likely discipline the market. Therefore, the MISO-IMM looks for abuses of market power and whether behavior is justified.

Furthermore, it is Staff's understanding that the MISO-IMM encourages MPs to include major maintenance expense in the respective generating unit offer curves while SPP does not. If, in the future, SPP requires or strongly encourages its MPs to offer in all baseload units at market commitment status, and the IOU does not alter its offer curve to reflect major maintenance

[11] Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company Response to Commission Questions, Pg 4.

[12] https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf, Pg. 5.

expense, customers are likely to be impacted negatively either through decreased off-system sales, increased probability of outages, decreased lifespan of assets and increased operations and maintenance expense without being required or encouraged to reflect those variables in the respective offer curves.

It is also Staff's understanding that the MISO-IMM does on-going analysis related to utility operations of a unit. It reviews the adherence of the operator of a generating plant to how that plant was bid and its relationship to congestion. If the MISO-IMM finds abuse, the MISO-IMM can and has brought penalties against a utility.

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<u>Interested Stakeholders' Comments:</u>

In its June 28, 2019, comments Sierra Club notes that several entities are reviewing the same issues raised by the Commission in this docket. Sierra Club states, "It is no secret that coal generators nationwide have struggled to remain economically competitive, which has a detrimental effect on ratepayers. Excessive and unwarranted self-generation by these same generators could compound the negative effects on ratepayers".[13] (footnotes omitted). Sierra Club identifies what it considers several flaws in the responses provided by the IOUs, noting Ameren Missouri provided no assessment of the impact of self-committing, and KCP&L and Empire provided select data. As Staff noted above, Sierra Club comments, "The inconsistent reporting makes it difficult to review the impact of self-commitment on ratepayers, or if the utilities' management of the units is reasonable and prudent".[14] Sierra Club goes on to identify what it considers "one of the most problematic elements", which is the "likely different

[13] Sierra Club Initial Comments. Pg. 4. June 28, 2019.

[14] Sierra Club's Comments on July 8, 2019 Informational Submissions. Pg. 3. July 23, 2019.

interpretation of production cost used by the different utilities."[15] Sierra Club explains that a determination of which production costs are variable will affect whether self-commitment is economic. Sierra Club provides comments on each IOUs' submissions. For instance, Sierra Club states, "Ameren does not submit sufficient evidence to allow the Commission to understand whether its self-commit and self-dispatch practices have inured to the benefit of customers...Ameren's case for self-commitment seems to rely in large part upon avoiding cycling costs that Ameren either does not know, or is unwilling to share with the Commission."[16] Similarly, Sierra Club states, "While some of KCP&L's explanations may have a degree of validity, the Company has not provided enough information to evaluate whether those justifications are reasonable when invoked in particular instances, nor explained how it ensures that decisions to self-schedule benefit its ratepayers".[17] Finally, while it provided specific confidential responses to Empire's data, Sierra Club generally notes that "Empire fails to describe whether or how it quantitatively assesses whether self-commitment benefits ratepayers" stating that it appears Empire's analysis to self-commit is based on general circumstances rather than a rigorous assessment of costs and benefits.[18]

On July 8, 2019, APA-CGA submitted the *Joint Initial Comments of Advanced Power Alliance and Clean Power Grid Alliance.* APA-CGA comments that while self-commitment and self-scheduling are not prohibited in SPP and MISO, they can cause customers to pay higher prices for energy than if the utility had procured from market resources. APA-CGA notes that self-committed and self-scheduled generation is "often less responsive to market prices, reducing the flexibility of the power system to efficiently respond to changes in electricity supply and demand" and the excess energy "can suppress market prices, harming other more cost-effective generators and undermining market efficiency". According to APA-CGA, a recent assessment by the Wind Solar Alliance estimates that self-scheduling resulted in excess fuel costs of at least $85 million in PJM and $127 million in MISO in 2017.[19] APA-CGA cites a report by the Union of Concerned Scientists, which suggests the total cost to consumers in MISO, SPP, PJM and ERCOT may be even higher. Finally, APA-CGA suggests that since the fuel adjustment clause

[15] Id.
[16] Id. at Pg. 4.
[17] Id. at Pg. 8.
[18] Id at Pg. 14.
[19] APA-CGA Initial Comments. Pg. 4. July 8, 2019.

(“FAC”) and other rate making matters fall within the realm of the Commission, it is appropriate for the Commission to explore the issue.

Staff also reached out to MISO and SPP. SPP responded that it probably did not have information that would be informative to the Commission’s inquiry.

Staff’s Conclusions:

*** *** In order to determine the level of benefit or detriment to ratepayers, Staff would need to run a simulation of a historical period, changing the must-run status for day ahead and real time markets while making sure all ancillary services are met. That kind of analysis would require Staff to obtain HC information on all generation assets in SPP and MISO and require Staff to be able to run a scenario to dispatch all plants with a market commit status. Staff does not have the tools to complete such a task. An alternative method could be to utilize data such as the Ventyx Eastern Interconnect model. That model is cost prohibitive. In addition, Ventyx uses some approximations as well as makes changes to the data to obtain what it believes is a reasonable result.

Given the geographical location of a vast majority of the units with respect to the load of the IOU, it is likely that the load node LMP is depressed when the units closest to load are dispatched. When LMPs are depressed at the load node, customers receive the benefit of decreased purchased power through the Fuel Adjustment Rates all else being equal. Given the resource limitations described in this Report, Staff is unable to quantify these affects but does recognize them at a qualitative level. To change all units to a market commit status would be such a fundamental change in the dispatching of units, it would raise questions as to whether any result would be reasonable. Such an analysis is beyond Staff’s technical resources and would need to be completed at the ISO level. *** ***

Stakeholders raise issues with the quality of data that was provided in response to this investigation. While not perfect, Staff was able to complete its investigation using that data, but makes recommendations below to improve on-going reporting and analysis.

When evaluating the economic decision to self-schedule a unit, it is important to take into account the entire bid when evaluating the revenue in excess of generation costs. Each variable a utility changes in the offer curve that is not tied to physical constraints or realities can and will influence the amount a unit may be dispatched above the self-commit economic minimum and thus impact the revenue in excess of generation costs.

Staff conducted analysis of the number of hours by month that each unit was dispatched at its economic minimum under self-commit or must-run status without any additional dispatch under the economic or market status. To merely analyze the number of hours that the unit is self-scheduled would not provide a clear picture of whether or not the decision to self-schedule was a good economic decision. If the RTO dispatched the units at a level of generation higher than the self-commit amount for a vast majority of the hours in the month, a clear customer benefit is demonstrated through economic operation of the plant so long as the bidding strategy is cost-based. If the number of hours that a unit is dispatched at the economic minimum under self-scheduled status is high, it does not necessarily indicate imprudence. For example, if a unit were only dispatched at the economic minimum under self-commit status during the evening hours but dispatched under economic or market status during the other hours in that day it may have been a sound economic decision to self-commit. If a unit is only dispatched at the economic minimum under self-commit status for a high number of hours in a given month, it could warrant additional research and discovery.

However, there is a possibility that a different strategy could increase the benefit to customers through maximization of off-system sales revenue and minimization of fuel costs. It is also possible that a change in strategy could cause customer harm through increased outage rates, decreased off-system sales revenue, increased operations and maintenance costs, shortened life of assets, increased outage frequency, decreased reliability, increased LMPs at the load node, and/or generally increased energy prices across the RTO's footprint. Staff is not making any ratemaking or prudence recommendations in this Report, but has begun reviewing self-committing as part of its FAC prudence reviews (See Attachment B for an example of information Staff requested in a recent FAC prudence review).

Staff plans to monitor the number of hours that units are dispatched at their economic minimum under self-scheduled or must-run status without any additional dispatch under the economic or market status in future prudence reviews.

	DAY AHEAD			
Row Labels	MWh at transmission voltage associated with retail load	MWh at transmission voltage associated with other purchases such as sale for wholesale customers.	MWh at transmission voltage associated with Qualifying Facilities, and with utility-owned generation that is not separately metered by the relevant RTO	LMP
7/1/17 0:00				
7/1/17 1:00				
7/1/17 2:00				
7/1/17 3:00				
7/1/17 4:00				
7/1/17 5:00				
7/1/17 6:00				
7/1/17 7:00				
7/1/17 8:00				
7/1/17 9:00				
7/1/17 10:00				
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7/1/17 17:00				
7/1/17 18:00				
7/1/17 19:00				
7/1/17 20:00				
7/1/17 21:00				
7/1/17 22:00				
7/1/17 23:00				

If service territory includes non-contiguous areas please provide separate information for each area, if available.

For example, utility owned solar, landfill gas generation, etc.

Please provide 3 years of hourly data.

If information is provided on sub-hourly interval please use separate sheet with rows desginated as sub-hourly increments.

REAL TIME			
MWh at transmission voltage associated with retail load	MWh at transmission voltage associated with other purchases such as sale for wholesale customers.	MWh at transmission voltage associated with Qualifying Facilities, and with utility-owned generation that is not separately metered by the relevant RTO	Hourly-weighed LMP

RTO cost per MWh of Load			Other RTO costs allocated on Load-Ratio share		
Charge Type 1	Charge Type 2	Charge Type 3	Charge Type 1	Charge Type 2	Charge Type 3

UNIT NAME	MISO Convention - Negative values = revenues and positive values = charges.							
Row Labels	OFFER STATUS	Cost offer ($/MWh)	MW offered DA	MW cleared DA	RT OFFER COST ($/MW)	MW offered other (add columns as needed to specify)	MW cleared as other (add columns as needed to specify)	RT ENERGY COST
7/1/17 0:00	MRUN							
7/1/17 1:00	MRUN							
7/1/17 2:00	MRUN							
7/1/17 3:00	MRUN							
7/1/17 4:00	MRUN							
7/1/17 5:00	MRUN							
7/1/17 6:00	MRUN							
7/1/17 7:00	MRUN							
7/1/17 8:00	MRUN							
7/1/17 9:00	MRUN							
7/1/17 10:00	MRUN							
7/1/17 11:00	MRUN							
7/1/17 12:00	MRUN							
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7/1/17 17:00	MRUN							
7/1/17 18:00	MRUN							
7/1/17 19:00	MRUN							
7/1/17 20:00	MRUN							
7/1/17 21:00	MRUN							
7/1/17 22:00	MRUN							
7/1/17 23:00	MRUN							
Grand Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -

Please provide 3 years of hourly data.

Provide for each Unit, for each hour, with a separate sheet for each unit.

MISO Convention - Negative values = revenues and positive values = charges.

Market Revenue Total	Contingency Reserve Deployment Failure Charge Amount	DA Asset Energy Amount	DA Asset Volume	DA Locational Marginal Price	DA Market Administration Amount	DA Regulation Amount	DA Revenue Sufficiency Guarantee Make Whole Payment Amount
$ -	$ -						
$ -							
$ -							
$ -							
$ -							
$ -							
$ -							
$ -							
$ -							
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$ -							
$ -	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ -**

MISO terms used in this example, please use terminology and schedule names relevant to RTO in which operated.

MISO Convention - Negative values = revenues and positive values = charges.							
DA Schedule 24 Allocation Amount	Excessive Energy Amount	Net Regulation Adjustment Amount	Non-Excessive Energy Amount	RT Excessive Deficient Deployment Charge Amount	RT Locational Marginal Price	RT Market Administration Amount	RT Metered Billable Volume
$ -	$ -	$ -	$ -	$ -		$ -	$ -

MISO Convention - Negative values = revenues and positive values = charges.									
RT Price Volatility Make Whole Payment	RT Regulation Amount	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	RT Revenue Sufficiency Guarantee Make Whole Payment	RT Schedule 24 Allocation Amount	RT Spinning Reserve Amount	RT Supplemental Reserve Amount	Volume of fuel burned	Contract price of fuel burned	VOM costs ($)
$ -	$ -	$ -	$ -	$ -	$ -	$ -			

UNIT NAME

1	Net Heat Rate Curve
2	Dates of forced outages/detrates/level of derate
3	Ramp up rate (curve if applicable)
4	Ramp down rate (curve if applicable)
5	RTO accredited ramp rate description if different
6	Minimum operating level
7	Maximum operating level
8	Maximum operating time and/or required outage intervals
9	Fully describe planned/anticipated outage intervals, and describe staffing levels during planned and forced outages.
10	Minimum down time descriptions and any special procedures or considerations (for example, if Unit A requires Unit B for auxillary power during startup)
11	Auxillary power source and description for site
12	Description of start-up fuel requirements
13	Descriptions of PPAs/contracts in place during study period (include descriptions of any intervals such as summer capacity only, or changes in contract participants during study period)
14	Descriptions of fuel and additive purchase arangements in place during study period (include descriptions of any intervals such as sesasonal variations, or changes in contract participants during study period). Please identify any Take or Pay provisions, and describe level of storage capabilities including prefered minimum days' burn of storage and maximum days' burn of storage available.
15	Description of changes in level of staffing and associated labor costs for site as various numbers of units operate at variouis levels
16	Level of staffing and associated labor costs for site if no units are operating
17	Describe other variable operating costs, including the metric that introduces variability (for example, additional staff required to apply deicer, but only in certain weather conditions).
18	Describe impact of emissions allowance or related environmental compliance (including waste disposal and cooling if applicable) on unit run decisions.
19	Describe how offer price is calculated, specifically how items such as ToP fuel costs and non-variable labor are (aren't) accounted for in offer price). Describe if/how this has changed through time.
20	Fully describe no-load costs, startup and shut down costs.
21	Fully describe transmission arrangements in place that are related to the realized price of unit operation relative to load, for example FTRs/ATRs, and how those impact the realized price of unit/load market participation. If relevant, provide hourly data.
22	**Describe any RTO or transmission-related constraints or instructions that impact unit run decisions, for example, if a higher-priced unit is run to provide voltage support or avoid loop flow conditions.**
23	Describe any other information relevant to unit, such as if located distant from load, if utility is not sole operator of unit, level of utility's control over day-to-day operations, etc)
24	Describe any other information relevant to understanding the day-to-day decision to operate the unit at a given level in a given market.

Provide for each Unit, for each hour, with a separate sheet for each unit.

If answers for questions are the same for multiple units at a site, please indicate "See Unit X" or similar for response on subsequent units.

Generating Facility

MISO Convention - Negative values = Revenues/Generation and Positive values = Charges/Station Use

Date	DA OFFER STATUS	RT OFFER STATUS	RT OFFER COST ($/MW)	RT ENERGY COST	Market Revenue Total	Net Settlement	Contingency Reserve Deployment Failure Charge Amount	DA Asset Energy Amount	DA Asset Volume	DA Locational Marginal Price
6/1/2017 0:00	MRUN	MRUN								
6/1/2017 1:00	MRUN	MRUN								
6/1/2017 2:00	MRUN	MRUN								
6/1/2017 3:00	MRUN	MRUN								
6/1/2017 4:00	MRUN	MRUN								
6/1/2017 5:00	MRUN	MRUN								
6/1/2017 6:00	MRUN	MRUN								
6/1/2017 7:00	MRUN	MRUN								
6/1/2017 8:00	MRUN	MRUN								
6/1/2017 9:00	MRUN	MRUN								
6/1/2017 10:00	MRUN	MRUN								
6/1/2017 11:00	MRUN	MRUN								
6/1/2017 12:00	MRUN	MRUN								
6/1/2017 13:00	MRUN	MRUN								
6/1/2017 14:00	MRUN	MRUN								
6/1/2017 15:00	MRUN	MRUN								
6/1/2017 16:00	MRUN	MRUN								
6/1/2017 17:00	MRUN	MRUN								
6/1/2017 18:00	MRUN	MRUN								
6/1/2017 19:00	MRUN	MRUN								
6/1/2017 20:00	MRUN	MRUN								
6/1/2017 21:00	MRUN	MRUN								
6/1/2017 22:00	MRUN	MRUN								
6/1/2017 23:00	MRUN	MRUN								

MISO Convention - Negative values = Revenues/Generation and Positive values = Charges/Station Use

DA Market Administration Amount	DA Regulation Amount	DA Spinning Reserve Amount	DA Supplemental Reserve Amount	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	DA Schedule 24 Allocation Amount	Excessive Energy Amount	Net Regulation Adjustment Amount	Non-Excessive Energy Amount	RT Excessive Deficient Deployment Charge Amount	RT Locational Marginal Price

MISO Convention - Negative values = Revenues/Generation and Positive values = Charges/Station Use

RT Market Administration Amount	RT Metered Billable Volume	RT Price Volatility Make Whole Payment	RT Regulation Amount	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	RT Schedule 24 Allocation Amount	RT Spinning Reserve Amount	RT Supplemental Reserve Amount