**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of the Application of Kansas City Power & Light Company for Approval of 2018 Actual Cost Adjustment ("ACA")	))))	Docket No. 19-KCPE-353-ACA

NOTICE OF FILING OF STAFF'S PUBLIC REPORT AND RECOMMENDATION

The Staff of the Kansas Corporation Commission (Staff and Commission, respectively), having investigated the issues presented in this docket, hereby files its attached Report and Recommendation (R&R). Staff recommends the Commission approve Evergy Kansas Metro, Inc., f/k/a Kansas City Power and Light Company's (KCP&L)[1] ACA factor of $0.00108 per kWh, reflecting an under-collection of fuel and purchased power costs from retail customers during the 2018 calendar year of $6,901,525. Staff's detailed analysis is discussed further in this Report.

In addition to its normal ACA audit and Report, Staff performed an evaluation of KCP&L's self-commitment behavior and decisions to self-commit its coal-fired generation during the 2018 year. Staff did not find any imprudence in KCP&L's management of the self-commitment of its coal fleet. The revenue generated from KCP&L's coal units exceeded the marginal cost of production for the vast majority of the time the units were self-committed, when viewing the data in aggregate. Staff's detailed findings are presented in the Self-Commitment Analysis section of this Report.

[1] To remain consistent with the docket caption in this case, Staff refers to Evergy Kansas Metro, Inc. by its prior name, KCP&L, throughout this report.

WHEREFORE, Staff respectfully requests that the Commission adopt its recommendation of approving KCP&L's ACA factor.

Respectfully Submitted,

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REPORT AND RECOMMENDATION
UTILITIES DIVISION

REDACTED VERSION
** [redacted] ** Denotes Confidential Information

TO: Chair Susan K. Duffy
Commissioner Dwight D. Keen
Commissioner Andrew J. French

FROM: Chad Unrein, Senior Managing Auditor/FERC Affairs Specialist
Ian Campbell, Auditor
Tim Rehagen, Senior Auditor
Bill Baldry, Senior Auditor
Kristina Luke Fry, Managing Auditor
Justin Grady, Chief of Revenue Requirements, Cost of Service and Finance
Jeff McClanahan, Director of Utilities

DATE: January 12, 2021

SUBJECT: 19-KCPE-353-ACA: In the Matter of the Application of Kansas City Power & Light Company for Approval of 2018 Actual Cost Adjustment ("ACA").

EXECUTIVE SUMMARY:

On March 1, 2019, Evergy Kansas Metro, Inc., f/k/a Kansas City Power and Light Company (KCP&L)[1] filed an Application for approval of its annual ACA. KCP&L requested an ACA factor of $0.00108 per kWh, reflecting an under-collection of fuel and purchased power costs from retail customers during the 2018 calendar year of $6,901,525. Staff conducted an audit of the ACA costs and recommends approval of KCP&L's request, which is discussed in the analysis section below. In addition to its normal ACA audit and Report, Staff performed an evaluation of KCP&L's self-commitment behavior and decisions to self-commit its coal-fired generation during the 2018 year. The detailed findings are presented in the Self-Commitment Analysis section of this Report. In its analysis, Staff did not find any imprudence in KCP&L's management of the self-commitment of its coal fleet. Furthermore, the revenue generated from KCP&L's coal units exceeded the marginal cost of production for the vast majority of the time the units were self-committed and when the data was viewed in aggregate.

[1] To remain consistent with the docket caption. Staff will refer to the Company as KCP&L, hereinafter.

BACKGROUND:

On March 1, 2019, KCP&L filed an Application requesting approval of its ACA for the Energy Cost Adjustment (ECA) year ending December 31, 2018. Accompanying KCP&L's Application are the testimonies of KCP&L witnesses Elizabeth A. Herrington and James M. Flucke. Ms. Herrington, Director of Power Energy and Revenue Accounting for KCP&L, supports the specific monthly calculations of the over/under-recovery for each month in 2018.[2] She also discusses the specific revenues and expenses that impacted the ACA calculation during the year 2018.[3] As Ms. Herrington supports, KCP&L's Application reflects an under-recovery of $6,901,525 in fuel and purchased power costs for the 2018 ECA calendar year. This under-recovery translates into a positive ACA factor of $0.00108 per kWh, which increased KCP&L's ECA factors for the months of April 2019 through March 2020. KCP&L witness James Fluke, Manager of Analytics, provided direct testimony containing a summary of information including KCP&L's quarterly ECA submittals; KCP&L's fuel procurement planning and practices; and a comparison of KCP&L's projected 2018 ECA to its actual 2018 ECA. Additionally, Mr. Fluke provides supplemental Testimony on the benefits derived from the Southwest Power Pool (SPP) Integrated Market, specific to the Consolidated Balancing Authority (CBA) for KCP&L's customers.

On March 1, 2014, SPP implemented the Integrated Market (IM).[4] The IM is a regional day-ahead energy and operating reserve market featuring the following major functions:

- Day-ahead energy and operating reserve markets;
- Day-ahead and intra-day Reliability Unit Commitment processes;
- Real-time balancing market;
- Price-based, co-optimized energy and operating reserve procurement;
- Market-based congestion management processes including Auction Revenue Rights (ARRs) and Transmission Congestion Rights (TCRs);
- Multi-Day Reliability assessment to manage the commitment of long-start resources; and
- Market Monitoring and Mitigation with an internal Market Monitoring Unit.[5]

With the implementation of the IM, KCP&L sells energy and operating reserves produced from its Company-owned generating resources to SPP in the Day-Ahead (DA) and Real-Time Balancing Market (RTBM) and purchases the energy and operating reserves it needs to serve its native load obligations on a daily basis. Revenues and expenses resulting from KCP&L's participation in the SPP IM are recorded in separate FERC accounts and recovered through KCP&L's ECA tariff. Staff expanded the scope of the ACA audit in 2014 to include a review of KCP&L's participation in the SPP IM. Staff continues to monitor and review KCP&L's monthly

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[2] Schedule EAH-2, attached to Ms. Herrington's testimony, provides the monthly calculation of the annual over/under-recovery of energy costs for the 2018 ECA year.

[3] Schedule EAH-3, attached to Ms. Herrington's testimony, provides the detail for each of the components that make up the total energy costs to be recovered, total ECA revenue collected, and the resulting ACA amount.

[4] *See* FERC, *Order on Compliance Filing*, January 29, 2014, Docket Nos. ER12-1179 and ER13-1173; https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14181773.

[5] *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012) (October 2012 Order).

market activity and performs a yearly review of controls, procedures, and performance as part of the annual ACA audit.

The practice of self-committing coal-fired generating units has drawn the attention of utility regulators, industry and environmental groups, and independent market monitors of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). Additionally, environmental advocacy groups, such as the Sierra Club, have published multiple studies alleging that the self-commitment practices of regulated utilities have resulted in harmful impacts to captive ratepayers and wholesale energy markets. Staff has been actively following and reviewing these articles, research papers, and general investigations that have addressed the self-commitment practices of regulated utilities. Excessive self-commitment of generation assets – when unwarranted – has the potential to suppress wholesale market prices and raise the production costs to serve load, thereby potentially harming ratepayers. This occurs because self-committed units can circumvent unit commitment and reorder "merit-based" dispatch, which can displace lower-cost regional energy providers to the detriment of utility ratepayers. As part of the ACA review, Staff elected to provide a detailed examination of the self-commitment practices of Kansas-jurisdictional utilities to determine whether the practices have negatively affected retail ratepayers in Kansas.

The Sierra Club has argued that self-commitment practices employed by regulated utilities amounts to a "back-door subsidy" or a "regional bailout" for coal-fired generation. These claims were made within several studies on the practice of self-commitment by regulated utilities and merchant generators across multiple ISO/RTOs.[6] In its study on Evergy Kansas Metro and Evergy Kansas Central's Kansas-jurisdictional operations, Sierra Club stated that Evergy's Kansas coal-fleet lost $267 million from 2015 – 2018.[7] It is important to understand that Sierra Club's analysis relies on historic net energy revenues less the fuel, variable operating and maintenance (O&M) costs and *fixed* O&M costs to operate the facilities. Sierra Club's analysis does not include any capital maintenance expenditures and similarly ignores any capacity benefit of these power plants. Staff provides an overview of the research conducted by Sierra Club and details the methodology used to calculate the impact to customers. Additionally, Staff provides its opinion of the Sierra Club's analysis and calculation methodology for determining the ratepayer impact of Evergy's self-commitment decisions for its coal fleet. Staff's analysis of the Sierra Club's studies is included in Appendix B of this Report.

The Missouri Public Service Commission (MPSC) opened a General Investigation of Generator Self-Commitment in the SPP and MISO markets (MPSC GI) in Docket EW-2019-0370.[8] On August 23, 2019, the Staff of MPSC (MPSC-Staff) issued its general report finding no evidence that customers are being actively harmed by the Missouri IOUs' market strategy regarding self-

[6] In 2019, Sierra Club released three studies including: (1) Kansas Pays the Price: A Comparison of Coal Plants and Renewable Energy for Electric Consumers of Evergy, KCP&L, and Westar; (2) Backdoor Subsidies for Coal in the Southwest Power Pool; and (3) Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets.
[7] *See* Sierra Club's study "Kansas Pays the Price" page 1. https://coal.sierraclub.org/sites/nat-coal/files/2071_Kansas-Pays-Price-Evergy-Whitepaper_06_web.pdf.
[8] *See* MPSC GI in Docket No EW 2019-0370; https://www.efis.psc.mo.gov/mpsc/DocketSheet.html.

committing units.[9] In addition to the general report, the MPSC-Staff provided utility specific analysis regarding KCP&L's practice of self-committing its coal-fired resources, which was filed in Docket No. EW-2020-0033 to protect the confidential and market sensitive nature of the data.[10]

Staff requested KCP&L provide access to the confidential reports and self-commitment data used in Missouri's study. The utility-specific reports feature a detailed look at KCP&L's use of self-commitment of its coal units. It examines KCP&L's commitment decision to determine whether self-committed units produced enough revenue to cover the short-run variable costs of production during self-committed hours. Similar to the MPSC-Staff Report, Staff used a contribution margin analysis to evaluate self-commitment of coal units in this ACA proceeding. Staff contends that a contribution margin analysis is the appropriate methodology to determine and quantify the ratepayer benefit or detriment that result from *self-commitment decisions*, as the analysis will detail whether the unit's revenue *exceeds the variable cost* of operating the unit. To the extent unit revenue exceeds the variable production costs, the revenue contributes to the fixed cost recovery of the unit; and therefore, reduces the overall cost of the unit for ratepayers. Unlike the analysis conducted by the Sierra Club, a contribution margin analysis recognizes that the fixed production cost of a unit are "sunk" in the near-term, and these sunk costs exist absent a unit's production. It also makes sense to evaluate whether variable costs are being covered during self-commitment windows because the vast majority of costs subject to this ACA proceeding are variable production costs.

In addition to MPSC GI, the SPP Market Monitoring Unit (MMU) published a Whitepaper entitled "Self-committing in SPP Markets: Overview, Impacts and Recommendations" (MMU Whitepaper).[11] The MMU Whitepaper explores the self-commitment offer behavior in the SPP IM and describes how self-commitment can affect market participants and market outcomes. The MMU Whitepaper includes two primary tracks of study used by the MMU to examine the self-commitment of coal units and the impact of self-commitment on the SPP IM. The first track of the MMU's study included an empirical review of offer behavior in the SPP IM from March 2014 to August 2019. The second track of the MMU's study included a series of simulations that resettled the historical DA market. The simulations were conducted on the first week of DA market solutions per month from September of 2018 to August of 2019. The simulations were designed to explore the following market assumptions: (1) all generation is offered in market status; and (2) all generation offered in market status can be started economically by the day-ahead market. For each market scenario, the MMU examined the market impact of the commitment assumption on the market clearing prices and regional production costs in SPP. Staff provides a detailed review of the MMU's simulation methodology and discusses the market impact of each resettlement scenario in the Self-Commitment Analysis attached as Appendix B to this Report.

[9] *See* MPSC-Staff Report (Public) in Docket No. EW-2019-0370, filed on August 23, 2019; https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936239578.

[10] *See* Appendix A of MPSC-Staff Report (Public) for its analysis of KCP&L use of self-commitment filed in EW-2020-0033; https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936239593.

[11] See MMU Whitepaper on "Self-Committing in SPP Markets: Overview, Impacts, and Recommendations; https://www.spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

In its findings, the MMU concluded that the key to reducing self-commitment while not increasing production costs is to expand the unit commitment window by instituting a market design enhancement for multi-day unit commitment. Increasing the optimization window by an additional twenty-four hours allows the market to optimize resources with long start-up times more effectively. The MMU found that this enhancement, if paired with a reduction in self-commitment, would benefit ratepayers by reducing production costs. The design enhancement would likely result in less distortion to the pricing and investment signals that drive the decision-making processes of market participants. Additionally, the MMU concluded that eliminating self-commitment without lengthening the optimization window would result in more clear investment signals, but would *likely raise total production costs*. The MMU's recommendation supports the finding of the SPP Holistic Integrated Tariff Team (HITT) to evaluate a multi-day optimization as a market design enhancement. This market enhancement has the potential to increase market efficiency and reduce the self-commitment of coal units in SPP.

Given the current limitations of the unit commitment optimization, utilities will continue to use self-commitment as a tool to manage unit commitment in the SPP IM. Staff's analysis will provide the Commission with a primer on the use of self-commitment practices by Kansas-jurisdictional utilities and explore the steps Kansas-jurisdictional utilities have taken to reduce self-commitment of coal units. Additionally, Staff will present its own analysis on self-commitment practices of KCP&L and incorporate the research provided by other parties examining the market effects of self-commitment. Staff's findings support that KCP&L has been actively evaluating its self-commitment practices of its coal units in response to changing conditions in the SPP wholesale market.

ANALYSIS:

Traditional Fuel and Purchased Power Review

Staff solicited from KCP&L, via formal discovery requests, phone calls, and e-mails, documentation supporting its Application and Schedules EAH-2 and EAH-3. Staff performed the majority of its audit in-house using the information gathered through this process. Once Staff's desk audit was mostly complete, Staff met with KCP&L at its corporate offices in Kansas City. This meeting allowed Staff to further question KCP&L about information provided in response to data requests and to review KCP&L's coal and rail transportation contracts. Staff notes that KCP&L personnel were cooperative and helpful when answering Staff's questions and providing requested supporting documentation. Staff audited KCP&L's actual fuel costs for the following months: May, June, October, and November 2018.[12] For these months, Staff conducted an audit of the Application that consisted of:

- Verifying the accuracy of the monthly settlement computations by ensuring the ACA factor calculated by KCP&L reflects the actual over/under-recoveries and the actual kWh sales to Kansas jurisdictional customers;

[12] Since the reimplementation of KCP&L's ECA in 2008, it has been Staff's practice to audit four sample months in the ECA year. This typically involves at least two high-volume summer months and two shoulder months.

- Ensuring that the actual fuel, purchased power, and emissions costs recovered through the ECA are actual costs supported by vendor invoices and general ledger entries; and
- Verifying that the ECA factor used to calculate the customer's bill agrees with the calculation that the Company files with the Commission.

During this portion of Staff's audit, no material irregularities were found in the information provided by KCP&L.

SPP Integrated Marketplace Review

As referenced in the Background Section above, Staff's expanded ACA audit includes the review of KCP&L's participation in the SPP IM during 2018. Staff issued formal discovery requests to document KCP&L's processes and procedures involving its day-to-day operations within the SPP IM.

The objectives of Staff's audit of KCP&L's participation in the IM were as follows:

1. Review KCP&L's process and control procedures in place to validate the accuracy of SPP invoices and statements.
2. Examine KCP&L's management of market performance and operational risk within the SPP IM.
3. For the months being audited in this year's ACA audit, evaluate whether KCP&L has accurately accounted for Kansas' actual share of IM revenue and costs pursuant to the provisions of the current ACA tariff.
4. Determine whether KCP&L's participation in the SPP IM is providing benefits to KCP&L's Kansas ratepayers.

Processes & Control Procedures

In order to examine KCP&L's control procedures entailing verification of its SPP IM billing statements, Staff issued formal discovery requests based on the findings of the SPP audit and the review of fuel and purchase power expenses in KCP&L's ACA in 2017.[13]

Staff requested KCP&L provide any updated information regarding the software application that KCP&L utilizes to interact with the IM and documentation of KCP&L's process and control procedures.[14] KCP&L continues to use Power Costs, Inc. (PCI) software suite, which includes PCI's GenBase and GenManager to manage its generation portfolio and Application Programmable Interface interactions with the SPP IM. KCP&L's software systems remain unchanged from the 2017 ACA audit, and a detailed review of KCP&L's software can be found in Staff's Report and Recommendation filed in Docket No. 15-KCPE-381-ACA.

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[13] *See* Staff's Report & Recommendation in Docket No. 17-KCPE-400-ACA (October 20, 2017).

[14] Shadow settlements are settlement statements independently recalculated by the utility to check against the daily settlement statements produced by SPP. A settlement statement contains all of the daily charges related to the IM for that operating day by charge type.

In prior audits, KCP&L provided Staff with detailed documentation of KCP&L's processes, procedures, and controls encompassing all SPP IM activities. KCP&L did not have any changes or additions to the processes and procedures for SPP IM activities. Staff examined KCP&L's processes for DA and RTBM activities, shadow settlement, and settlement statement verification. KCP&L has developed both Operating Letters and an intracompany SPP IM User Guide, which document KCP&L's procedures for SPP IM activities. The User Guide details all of the different tasks that must be completed throughout the day for participation in the SPP DA and RTBM. The User Guide acts as a resource for KCP&L's Power Systems Operators, Traders, and Schedulers. The User Guide is periodically reviewed and updated as the Company's processes change for SPP IM activities. KCP&L uses its shadow settlement system and meter data to verify SPP IM activity independently and compares the resulting solution against the SPP settlement statements. The SPP settlement statements contain all of KCP&L's net revenue and charges related to its market activities for the operating day by charge type. If the shadow settlement calculation deviates from the SPP invoice, KCP&L reviews the internal shadow settlement calculation and meter data and, if necessary, files a dispute in the SPP marketplace portal.

In Staff's evaluation, KCP&L has robust control procedures in place to verify the accuracy of the settlement statements and invoices it receives from SPP for its activity in the IM. KCP&L has a comprehensive process in place to verify meter data with internal and external counterparties and with SPP. Furthermore, KCP&L has a defined process in place to submit and monitor disputes with SPP.

Market Performance and Operational Risk

In order to examine whether KCP&L was diligently managing its risks associated with the IM in its audit of 2018 costs, Staff issued discovery requests regarding KCP&L's procedures for determining the profitability of incremental market sales associated with the SPP IM. The actual accounting processes, calculations, and strategies are complex and highly confidential; however, this information remains available for the Commission's review should the need arise.

Staff issued formal discovery requests regarding KCP&L's strategy for offering its generating resources into the IM and bidding for the daily load necessary to serve customers. KCP&L discussed its strategy in pursuing additional market sales through bilateral transactions when pricing opportunities occur in the market. While bilateral transactions have significantly decreased since the start of the market in 2014, KCP&L continues to look for opportunities to execute bilateral contracts. These contracts help to reduce the cost of generation or increase revenue from KCP&L's generation assets. KCP&L did not execute any bilateral transaction in 2018.

Staff examined KCP&L's practices for developing and updating fuel costs and variable operating and maintenance costs associated with developing its resource offers. KCP&L uses PCI P&L Analyzer to calculate and track the profitability of its generating units for both DA and RTBM. KCP&L summarizes its market activity in a monthly report containing a profit and loss analysis and revenue deficiencies by unit. While the details of KCP&L's strategies are confidential due to their competitive and market-sensitive nature, Staff finds that KCP&L has developed strategies that allow it to manage risks (including risks of recovery of variable O&M costs and fuel cost changes) and evaluate its profitability in order to be successful in the SPP IM.

Staff issued discovery requesting KCP&L detail its hedging strategies and procedures for managing its congestion portfolio of ARRs and TCRs within the SPP IM.[15] In its responses, KCP&L stated that its strategy was to self-convert its allocated ARRs to TCRs within the expected unit capacity requirements and all of KCP&L's allocated ARRs with an expected positive path value were converted to TCRs in 2018. KCP&L experienced an increase in congestion cost and the revenue generated from its ARR and TCR positions in 2018. KCP&L's total congestion cost exposure was ** [redacted] ** while the revenue generated from its ARR and TCR positions totaled ** [redacted] **. KCP&L's total congestion portfolio accounted for a net benefit of ** [redacted] ** after accounting for additional purchases and sales of TCR in 2018.[16] In comparison to 2017, KCP&L's congestion cost exposure was ** [redacted] ** while the revenue generated from its ARR/ TCR positions totaled ** [redacted] **. KCP&L provided a revenue breakdown of its TCR portfolio by TCR product categories including: self-converted TCR revenue totaled ** [redacted] **; Long-Term Congestion Rights (LTCR) revenue totaled ** [redacted] **; and TCRs obtained from monthly-auctions totaled ** [redacted] **.

KCP&L has documented its policies for managing its operational and market risk in its Energy Trading and Risk Management Policy. Additionally, KCP&L maintains a list of Marketer Authority Limits for its employees involved in the sales and procurement of power and natural gas. While the details of KCP&L's strategies are confidential due to their competitive and market-sensitive nature, Staff found that KCP&L has developed strategies that allow it to manage risks (including risks of recovery of variable O&M costs and fuel cost changes) and evaluate profitability to be successful in the IM. As part of KCP&L's merger process with Westar Energy, Inc. (Westar), the Risk Management Department pursued a consistent policy across all the jurisdictions. To accommodate the goal, KCP&L adopted the form of the legacy Westar policy; however, the philosophies between the policies were similar regarding governance, segregations of duties, SPP activity, and authority limits. The policy document incorporated all the material aspects of the legacy KCP&L Credit Policy.

In Staff's evaluation, KCP&L has the processes and procedures in place to evaluate both market risk and performance in both the DA and RTBM. The strategies KCP&L utilizes in managing congestion exposure appears to have been successful as KCP&L generated revenue of approximately ** [redacted] ** from its ARR/TCR portfolio net of KCP&L's realized day-ahead

[15] ARRs and TCRs are congestion management products that allow market participants to hedge their exposure to Marginal Congestion Costs in the IM. ARRs are allocated to entities with firm transmission rights on the transmission system, for example, a vertically integrated, investor-owned utility that uses its Network Integrated Transmission Service to serve its retail load. An ARR entitles the holder to a share of revenues generated in an applicable TCR auction, or the ARR may be converted into a TCR. A TCR allows a holder to be compensated or charged for congestion between two settlement locations in the day-ahead market. ARRs (indirectly) and TCRs (directly) derive their value based on the difference between the congestion price at the source settlement location less the congestion price at the sink settlement location multiplied by the awarded MW quantity over the specific path.

[16] The net benefit calculation includes TCR sales of ** [redacted] ** and TCR purchases of ** [redacted] **.

congestion in the IM during 2018. In its review of market risk and performance, Staff finds that KCP&L has diligently managed the risks and profitability associated with the IM and is taking the steps necessary to be successful in the IM.

ACA Audit of Revenues and Costs

Prior to the go-live date of the IM, Staff implemented a monthly review process to monitor the IM activity of the three vertically integrated, investor-owned electric utilities in the State of Kansas. This process involves the submission of monthly financial reports (Monthly Activity Report) to the Kansas Corporation Commission's Utilities Division that details each utility's operations in the SPP IM.[17] The Activity Reports provide a summary-level view of how the electric utility is faring in the marketplace and detail all SPP IM activity by charge-type. For example, Staff can view the amount of MWhs and average price of day-ahead or real-time asset energy KCP&L sold into the IM. Likewise, the Activity Reports summarize the energy and operating reserve products KCP&L purchased from the IM for the month, the MWhs associated, and the net dollar impact of those products. The Activity Reports allow Staff to monitor utility performance in the SPP IM, track trends in the wholesale energy market, and serve as a useful audit tool during the ACA audit. Finally, these reports provide the foundation for reconciling the monthly IM charges from SPP settlement statements and invoices to the journal entries recorded in the Company's general ledger. This data ties back to KCP&L's ACA Application and true-up of the over/under recovery of actual costs.

In addition to the Monthly Activity Report detailing IM energy and operating reserve activity, Staff also receives a monthly report from each Kansas jurisdictional electric utility detailing any virtual transactions undertaken in the SPP day-ahead market (Monthly Virtual Transaction Report). Staff reviews these reports to ensure that only virtual transactions with a legitimate hedging basis are recovered from Kansas ratepayers.

As part of Staff's review of KCP&L's participation in the IM, KCP&L provided Staff with a reconciliation that documented and verified all KCP&L IM activity for the audited months. This reconciliation relied on the SPP IM Monthly Activity Report discussed above, weekly SPP settlement statements, and a reconciliation spreadsheet prepared by KCP&L that tied net general ledger accounting data for the month back to the corresponding settlement statements and the Monthly Activity Report. KCP&L provided a reconciliation workpaper that allowed Staff to tie-out the allocation of ARR/TCRs between the KCPS and GMO asset owner. Due to its combined Network Integrated Transmission Agreement, SPP charges all the ARR and TCR value to the KCPS asset owner. KCP&L allocates GMO's portion of ARRs and TCRs in its Accounting Manager system based on the path of the ARR/TCR. After accounting for the ARR and TCR allocation, Staff was able to verify KCP&L's IM purchase and sales amounts presented in the Monthly Activity Report and tie these values to KCP&L's general ledger.

[17] Kansas City Power & Light and Empire each voluntarily agreed to the reporting requirements originally approved by the Commission for Westar Energy in Docket No. 14-WSEE-208-TAR (14-208 Docket). *See* items 15 and 16 in Attachment A of the Order Approving Tariff Revisions issued on February 25, 2014, in the 14-208 Docket.

In Staff's review of KCP&L's IM revenue and costs, Staff determined that the SPP settlement statements and the Monthly Activity Reports were accurately reported on KCP&L's general ledger and tied to KCP&L's ACA Application for the sample months audited.

SPP IM Benefit & Analysis of All-in Fuel Cost

In order to evaluate whether KCP&L's participation in the IM provided benefits to its Kansas customers in 2018, Staff issued formal discovery and examined other publicly available data. SPP has estimated that the IM has provided a net benefit to the region of $728 million in 2018, and $2.7 billion from its inception in 2014. This information suggests KCP&L's participation in the SPP IM produced benefits for Kansas ratepayers in 2018. At the highest level, KCP&L's total ECA eligible costs were ** [redacted] ** for the ACA year ending December 31, 2017, which was an increase of ** [redacted] ** over the 2017 ACA period. During the same period, total kWh delivered to Kansas increased by ** [redacted] **. For 2018, the total Kansas fuel and purchased power cost per kWh was ** [redacted] **, which was a year-over-year increase of ** [redacted] ** over the 2017 ACA. The year-over-year results were driven by increases in fuel, purchased power costs, emission costs, and transmission expenses.

In 2018, the fuel costs for steam production were lower due to a scheduled outage from March 2 to July 10 at Iatan 2 for a major boiler overhaul, system tuning, and resolving other maintenance issues discovered when the plant was brought back online. Additionally, Wolf Creek was offline from March 31 through May 18 for a refueling outage. The net impact reduced steam and nuclear fuel costs by ** [redacted] ** (values provided on a total-company basis). KCP&L's fuel cost reduction was entirely offset by increased fuel cost for oil and gas generation of ** [redacted] ** and purchase power expense increases of ** [redacted] ** due to lower baseload generation availability and higher retail load requirements. Due to its resource availability, KCP&L wholesale revenue decreased by ** [redacted] ** as less generation was available to sell. Emissions costs increased by approximately ** [redacted] **, and transmission expenses decreased by ** [redacted] ** for off-system sales, which provided a partial offset to the reduction in wholesale revenue. The net impact resulted in an increase of ** [redacted] ** in ECA eligible costs of which Kansas was allocated approximately ** [redacted] **.

KCP&L's off-system sales margin (OSSM) had a reduced impact on the ECA due to generation availability and increased retail load. KCP&L's OSSM loss totaled ** [redacted] **; however, the negative margin decreased by ** [redacted] ** when compared to 2017. KCP&L's negative OSSM is primarily driven by the relatively low wholesale market prices in SPP. KCP&L explained that the Company may "self-commit a unit to avoid cycling the unit on and off. Fewer cycles are expected to result in less wear and tear on the unit, fewer forced outages, lower maintenance cost over time, and longer unit life. Kansas OSSM is based on a calculation similar to "gross margin", which includes both fixed and variable production costs; however, off-system sales (OSS) decisions are based on a "contribution margin", which includes only variable costs. The rationale for the decision to sell based on a contribution margin is that any incremental sale contributes to the recovery of fixed production costs, which is a more favorable outcome than forgoing the sales opportunity. When looking at only the variable production cost, KCP&L OSS contributed ** [redacted] ** to the recovery of fixed production after recovering all the variable production costs. Additionally, KCP&L explained that in accounting for OSS, the generation unit responsible for the sale is determined after-the-fact by "restacking" the generation for each hour in order to assign the lowest cost resources to serve the Company's native load with the remaining higher cost resources assigned to OSS in the same hour. While this conservative assumption always assigns the lowest cost resources to retail sales, KCP&L's accounting process leads to a possible mismatch between its accounting records recording the OSS and the actual operating source of the OSS.

<u>Long-term Trends in KCP&L's All-in Fuel Cost</u>
Prior to the SPP IM, KCP&L's ratepayers benefitted by selling excess energy and generation capacity to various municipal and regional entities through bulk power revenue and off-system sales margins, which were credited against the cost to serve retail load. The margins provided a direct offset to production costs that were passed on to KCP&L's retail ratepayers. KCP&L's off-system sales margins have significantly decreased since the start of the SPP IM. As substantial investment in renewable generation entered the SPP market, the opportunity for wholesale sales from Kansas coal units decreased and the price of wholesale energy in SPP fell substantially. Margins from off system sales in most ECA rate periods have only covered the fuel cost and produced a contribution margin for the recovery of administrative fees and transmission expenses in the ACA. In the 2019 ACA, KCP&L produced ** [redacted] ** of the Kansas portion of OSSM when compared to a loss of ** [redacted] ** in the 2018 ACA, which represent a significant turnaround in its OSSM year-over-year.[18] ** [redacted] **

In each of the previous ACA audits, Staff has presented a Kansas retail all-in fuel or total ECA cost calculation. The calculation includes production fuel costs; purchased power expense; emission allowances; transmission costs; and SPP IM Activity, less Bulk Power Revenue & OSSM, which is then, apportioned to Kansas based on delivered MWh. Staff has used the metric as a performance tracking metric to guide discovery requests and determine underlying trends or cost drivers that impact market performance. Outside factors, such as SPP wholesale energy prices and Kansas demand for energy, can drive changes in the total ECA costs passed on to its Kansas-jurisdictional ratepayers. KCP&L's total ECA costs per Kansas-apportioned MWh for retail ratepayers has remained relatively flat with increases and decreases based on underlying factors in the market and KCP&L's market performance. From 2014 – 2019, Kansas all-in fuel cost has ranged from ** [redacted] ** increasing in three rate periods and decreasing in three rate periods.[19] Over the same periods, KCP&L all-in fuel costs per MWh for Kansas ratepayers has ranged from ** [redacted] ** increasing in three rate

[18] *See* Confidential Testimony of Elizabeth Herrington, Schedule EAH-3 in 20-EKME-242-ACA and 19-KCPE-353-ACA
[19] Confidential data from KCP&L Direct Testimony of Elizabeth Herrington, Schedule EAH-3 and the Direct Testimony of Ryan Bresette, Schedule RAB-3, in each of the annual ACA filings from 2013 – 2019. KCP&L's all-in Kansas fuel costs by rate year includes the following: ** [redacted] **

periods and decreasing in three rate periods.[20] In 2015, Kansas retail customers experienced its highest all-in fuel of ** [redacted] **, which also represented its highest year-over-year cost increase of ** [redacted] ** during the study period.[21] In 2019, KCP&L achieved its lowest Kansas all-in fuel cost of ** [redacted] **, which also represented it largest year-over-year reduction of ** [redacted] **.[22] For comparison purposes, KCP&L's ECA contained a Kansas apportioned retail fuel cost of ** [redacted] ** under the SPP Energy Imbalance Service (EIS) market in 2013.[23]

<u>Modeled Benefit of the SPP IM</u>
In compliance with the Commission's Order in the 16-KCPE-388-ACA, KCP&L prepared an SPP IM analysis examining the benefit to KCP&L's customers for SPP's Consolidated Balancing Authority (CBA). KCP&L's witness, James Fluke, explains in his Testimony that the CBA takes the responsibility of each market participant to balance load and transfers it to SPP for the entire footprint. The CBA reduces total system costs by matching lower cost generation to system demand more reliably. KCP&L's study examined the single market benefit associated with CBA because a cost-benefit study that examines the entire SPP IM is beyond the scope of this proceeding. KCP&L emphasized that the study will not be able to quantify the many other benefits of the SPP IM such as increased transmission construction, improved settlements, wind generation improvements, etc. The study measures the impact of KCP&L's native load improvement resulting from Locational Marginal Pricing as a proxy for the cost/benefit to serve native load. KCP&L performed a PROMOD simulation to measure the native system costs from the SPP IM and compared it to the old SPP EIS market in which KCP&L served its native load with its own generating resources for the entire year. KCP&L's calculation used its native load for both Missouri and Kansas and resulted in an estimated benefit of ** [redacted] ** for KCP&L's customers.

Staff has not performed a comprehensive review of the benefits and costs derived from KCP&L's participation in the various components of the SPP IM. Staff's analysis focused on short-run marginal costs of generating and transmitting power to serve KCP&L's load. Both the benefit calculation provided by SPP, and the independent model provided by KCP&L suggest customers are benefiting from the SPP IM. While KCP&L experienced a year-over-year cost increase of approximately ** [redacted] ** from a cost per kWh perspective, KCP&L's eligible ECA costs were significantly impacted by its baseload generating resource availability due to scheduled outages at Iatan 2 and Wolf Creek, increased retail load due to warmer weather, and wholesale revenue reductions due to resource availability. KCP&L's 2019 ACA resulted in a year-over-year reduction in the ECA costs per MWh of approximately ** [redacted] **. When considering the 2019 ACA results, Staff has observed a general decline in KCP&L's overall cost per kWh to serve its load since the implementation of the SPP IM; however, KCP&L's wholesale revenues have declined due to low wholesale market prices in SPP. Based on the available data from SPP, the

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[20] *See Id.* ** [redacted] **

[21] *See Id.*

[22] *See Id.*

[23] *See Id.*

modeled results performed by KCP&L, and the general decline in KCP&L's cost per kWh since the implementation of the IM, Staff's analysis suggests that the SPP IM is benefitting KCP&L's Kansas customers.

Self-Commitment of Baseload Coal-Fired Generation

As discussed in the Background Section, Staff included a review of KCP&L's self-commitment practices in the ACA audit. As part of the discovery process, Staff obtained access to the SPP market data for KCP&L's coal units and the Confidential Reports issued by the MPSC-Staff in its GI of KCP&L's self-commitment practices. Staff reviewed KCP&L operational strategies to manage the self-commitment of its coal fleet and examined the revenue and production expenses for each coal unit. Based on KCP&L's responses, Staff prepared a detailed analysis of KCP&L's unit commitment strategies and an economic evaluation of KCP&L's coal units. The following summary outlines the structure of Staff's Self-Commitment Analysis and details the analysis contained in each section of the Report.

I. Overview of the SPP Integrated Market (IM): Staff discusses the SPP IM structure and details the market processes responsible for minimizing production costs throughout the SPP footprint. This discussion reviews the five unit commitment statuses available for generators in SPP and details SPP's processes for setting the marginal energy price, determining resource dispatch, and generating locational pricing. Then, we explore the market incentives and market feedback mechanisms that drive the decision-making processes of market participants. Finally, we discuss how the economic and operating parameters of generating units drive the market interactions of resources with varying fuel types and detail how changes in the costs of fuel influence resource selection.

II. Market Function and Use of Self-Commitment by Kansas Utilities: Staff discusses the market function and use of self-commitment in energy markets. Then, we detail the market factors that contribute to the self-commitment of coal-fired generation in SPP. Next, we review Kansas utilities' practices for self-committing their coal-fired units. This review outlines market scenarios that lead to the self-commitment of coal units and explains the risks that are mitigated by the self-commitment of the unit. Finally, Staff provides its own analysis of market factors that drive the self-commitment of coal units and the operators' general objectives in managing unit commitment.

III. Effects of Self-Commitment in Energy Markets: Staff examines the market effects of self-committed generation in energy markets and explains how self-committed units alter the generation supply curve and resource dispatch. Then, we discuss how the current SPP market design contributes to the self-commitment of coal-fired generation. Finally, we discuss the impact of self-commitment on the marginal energy price, merit-based dispatch, pricing and investment signal distortion, and negative pricing intervals.

IV. Market Monitoring Unit (MMU) Whitepaper - Empirical Analysis and Simulations: Staff overviews the findings from the MMU's empirical study of market participants' offer behavior and details trends in the level of self-committed generation in the SPP IM. Then, we discuss the MMU's analysis and recommendations included in its Annual State of the Market Reports. Finally, we overview the MMU's market simulations studying two self-commitment scenarios. For each scenario, the MMU resettled the market to quantify the impact on marginal energy prices and regional production costs in SPP. In our review, we detail the MMU's study methodologies, examine the market impact of each settlement scenario, and discuss the MMU's recommendation to explore a market design enhancement for a multi-day unit commitment optimization.

V. Review of Sierra Club Studies: Staff provides a high-level overview of the self-commitment studies released by the Sierra Club in 2019. Then, we provide a detailed review of the Sierra Club's study entitled, "Kansas Pays the Price," that purports to quantify the ratepayer impact of Evergy's three large Kansas coal units. In the study, the Sierra Club calculates the market revenue from energy sales for each coal unit and compares the revenue against the unit's fuel and variable production costs plus the fixed operating, labor, and maintenance expenses. Following the revenue and cost review, we discuss the Sierra Club's recommendations to limit ratepayer exposure to the uneconomic operation of coal resources. Finally, we discuss our view of the Sierra Club's research and detail our differences of opinion with the Sierra Club's analysis.

VI. Review and Analysis of KCP&L Self-Commitment Practices: Staff reviews KCP&L's self-commitment strategies for managing its coal fleet and discusses the operator's ability to evaluate unit commitment decisions. Then, we overview our study methodology to examine KCP&L's self-commitment decisions using the historical market data of its coal units. Staff's approach is consistent with the study methodology employed by the MPSC-Staff in its Report. Finally, we overview the monthly revenue and market data for each coal unit and provide a comparison of aggregated yearly results to analyze changes in KCPL's self-commitment practices. Certain sections of Staff's analysis will be considered confidential as KCP&L's responses contain marketing analysis and market-specific data for services offered within a competitive wholesale energy market.

In order to provide a KCP&L-specific report, Staff's Self-Commitment Analysis included in Sections I through Section V are attached as Appendix B to this Report. Staff's Analysis of KCP&L's self-commitment strategies and market data can be found in Section VI below.

VI. Overview of KCP&L's Self-Commitment Practices for Managing its Coal Assets

In its examination of KCP&L's unit commitment strategies, Staff primarily relied on its discovery requesting access to documents, reports, data, and discovery provided by KCP&L in the MPSC – General Investigation. The MPSC GI examined the KCP&L self-commitment decisions from June of 2016 to June of 2019. Ultimately, Staff chose not to duplicate the full study efforts performed by the MPSC-Staff in its entirety. Staff agrees with the methodology used in the MPSC-Staff analysis, and the judicial use of administrative resources kept Staff from replicating the study in total. Portions of Staff's analysis will be considered confidential as KCP&L's responses contain marketing analysis and market-specific data for services offered within a competitive wholesale energy market.

Staff's Analysis of KCP&L's practices for self-committing its coal fleet consists of the following:

- We discuss some of the challenges in evaluating unit commitment strategies that limit regulatory commissions and KCP&L in providing a net-benefit/detriment calculation in the review of self-commitment strategies. We also detail how the MMU's Whitepaper calculating the market impact of self-commitment through its resettlement scenarios contribute to this conversation.
- We provide an overview of the utility operator's ability to economically evaluate and manage the self-commitment of its coal resources. Additionally, we discuss how our yearly audit of KCP&L's market activity in the SPP IM contributes to our confidence in the operator's ability to manage the self-commitment of its coal units.
- We detail KCP&L's operational strategies for managing its coal fleet and discuss how KCP&L analyzes the economic impact of self-commitment. Then, we review KCP&L's advances in the market-commitment of its coal fleet over the study period and compare the market-commitment of KCP&L's coal units against other coal units in the SPP IM.
- We review the study methodology employed by the MPSC-Staff to analyze the self-commitment of KCP&L's coal units, present the MPSC-Staff findings in its GI Report, and discuss the general conclusions reached by the MPSC-Staff based on its review of KCP&L's market data.
- We present aggregated market data on KCP&L's use of self-commitment for its coal units and analyze KCP&L's advancement in market-committing its coal feet during the study period. Finally, we present our general findings and recommendations to the Commission.

<u>Challenges in Calculating a Net Benefit/Detriment Calculation to Examine Unit Commitment</u>
Determining the level of ratepayer benefit or harm from self-commitment practices is data intensive and very complex. Typically, a net benefit calculation would require the simulation of historical market settlement periods, similar to the analysis conducted in the MMU Whitepaper, simulating the impact of altering unit commitment statuses of KCP&L's coal resources. Essentially, the simulation would necessitate confidential access to SPP's market data for all market participants and would simulate the resettlement of certain market periods to compare to the historical settlement period. Alternatively, a model could be developed with underlying assumptions and unit commitment data to approximate a reasonable result to the complete resettlement of the market. Both of these approaches would require Staff to rely on external consultants to perform the market analysis and modeling.

While the MPSC-Staff issued its report prior to the issuance of the MMU Whitepaper, Staff's Report has the benefit of the MMU's Whitepaper results simulating the net market impact of two self-commitment scenarios resettling the market.[24] While both of the MMU modeled scenarios

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[24] *See* Appendix B, Section IV, for Staff's Analysis of the MMU Whitepaper including a detailed breakdown of the MMU's resettlement methodology and the results of the two following resettlement scenarios. For, reference, Scenario 2 simulated the market impact of all units electing to "market-commit" all resources allowing a complete economic dispatch of market resources, which resulted in a 20% increase to the system marginal price or approximately $6 per MWh and an increase in regional production costs of 8% or more than $22,000 per hour. Scenario 3 simulated a lengthened optimization window, similar to multi-day unit commitment, which resulted in more than a 7% increase in the system marginal prices while slightly decreasing production cost of 0.5% or approximately $1,750 per hour.

produced increases to the wholesale market pricing (representing the price suppressing effects of self-commitment), Scenario 2 (which simulated a requirement for all generators to elect a market-commitment status) resulted in a significant increase to regional production costs. The MMU Study clearly demonstrates that the current unit commitment software has limitations in committing coal resources with long-lead times given that production costs increased significantly, which is contrary to the market design. Thus, the Sierra Club's recommendation for SPP to require the market-commitment and full economic dispatch of coal units would have a detrimental impact on integrated utility customers by raising production costs across the market. However, a requirement to market-commit coal resources would significantly raise the revenue of merchant generators and independent power producers operating renewable generation resources. The MMU's multi-day commitment scenario (Scenario 3) increased pricing and slightly lowered production costs supporting the evaluation of a market design enhancement for multi-day unit commitment that could provide integrated utilities a tool to lower the use of self-commitment further. The modeled result confirms the need for KCP&L to continue providing its own economic evaluation of coal-fired generation assets when electing a unit commitment status for its coal fleet.

<u>KCP&L's Operational Ability to Manage Unit Commitment</u>

Based on Staff's evaluation, Staff believes the utility operator is likely in the best position to examine past operating results and market conditions to determine if a coal unit is likely to produce operating margins over the expected commitment period. An operator may rely on past market data, wind and weather forecasts for the region, and the expected retail load and system demand when evaluating unit commitment. Generally, the SPP mitigated offer guidelines define the short-run marginal costs that can be included in a mitigated offer, which serve as a threshold for evaluating unit commitment and incremental energy sales. As discussed earlier, SPP IM Protocols only establish a guideline for mitigated offer costs, so utilities may have differing interpretations of the guidelines for production costs.[25] Mitigated offers are intended to capture the incremental energy cost of the unit, including the appropriate allocation of opportunity costs, of providing service for SPP energy and operating reserve markets. These production costs are evaluated by the MMU and are only used when offers are mitigated by the market. An operator's ability to accurately project revenue and maintain accurate production costs are critical in developing unit commitment and bidding strategies. Additionally, the real-time tracking of revenue deficiencies for units and continuous improvement of forecasting methodologies is necessary for a successful market strategy to maximize the ratepayer benefit of KCP&L's coal fleet.

From the initial implementation of the SPP IM, Staff initiated a process review of KCP&L's procedures and risk management policies for managing its market activity and evaluating the market risk of operating in the SPP IM. Staff confirmed that KCP&L has defined processes for analyzing past market bidding strategies with PCI software, tracking revenue deficiencies of its units, and analyzing deviations between day-ahead and real-time results with the P&L analyzer. KCP&L actively updates forecasting methodologies to manage its bid and offer strategies and updates in VOM costs accordingly. Ultimately, the potential for ratepayer harm exists from the election of an improper commitment status for an asset based on the underlying market conditions, or the real-time market results deviate from the forecasted DA market activity. An unsuccessful

[25] SPP provides mitigated offer guidelines can be found in Appendix G of the Integrated Marketplace Protocols.

self-commitment is likely to occur when wholesale market pricing is low across multiple market periods, resulting in negative margins and unrecovered production costs. An unsuccessful market commitment strategy can result in foregone margin opportunities, which can be counter-productive to the fixed cost recovery of the asset.

KCP&L's Operational Strategies for Managing Self-Commitment

In addition to issuing its own discovery, Staff requested access to the confidential reports produced by the MPSC-Staff, discovery responses, self-commitment data, and market strategies provided in the MPSC GI Docket. In discovery responses, KCP&L describes its operational strategy for managing the self-commitment of its coal fleet and provides some key drivers that influence its unit commitment decisions:

> KCP&L has worked to increase the percentage of time its power plants are market-scheduled. KCP&L fossil units are only self-scheduled with the Southwest Power Pool ("SPP") Market for safety, reliability, economic and environmental compliance reasons.
>
> Ensuring a plant is reliable and available to serve customers is one key factor. For example, cold weather can cause reliability issues in a steam-fired power plant due to water lines freezing, oil systems becoming too cold and even coal freezing. When facing environmental issues such as these, KCP&L may choose to self-commit a resource to protect that resource's equipment and thus ensuring its reliability.
>
> KCP&L may choose to self-commit a resource to prevent a thermal cycle or protect equipment that may pose a risk to the reliability of the resource as well. SPP's market model isn't always able to consider risks to KCP&L customer[s'] reliable power supply. If there are concerns about the effects of a thermal cycle on a resource or on a piece of equipment at that resource, KCP&L may choose to self-commit that resource. Managing the number of thermal cycles judicially will protect equipment thus reducing forced outages and unreliable starts due to the complexity of these large stations, all of which is a benefit to the retail customer.
>
> KCP&L may also choose to self-commit a resource for market economic reasons. Those decisions are made looking at wind and load forecasts to see if we can expect the resource to be economical 'x' days into the future. The SPP Market model does not currently do a good job committing large, baseload units with long lead times, large startup costs and long minimum run times. For example, SPP's Day-Ahead Market will not commit a unit with a startup time greater than 24 hours. Because of these restrictions, the Company has historically seen a high percentage of self-commitments at its baseload resources. Also, since SPP's tool only looks at the next day, there are times we might self-commit a unit that is already online knowing that over the next five total days we would be economic even though operations for the initial two days are at a financial loss; this results in lower overall costs to serve retail customers.
>
> 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 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 starts.[26]

Further, KCP&L describes how it analyzes and manages the economic impact of its unit commitment decisions:

> [T]he economic impact of a self-commit decision requires a wide area view model that can calculate the impacts of that self-commit decision on other generators, TCR's, load, LMP's. etc. in the SPP footprint. KCP&L does not have the ability to model those interdependencies. Further, the net impact to the retail customer cannot just be measured by looking at resources in isolation. SPP is the only group that can provide that type of system wide impact analysis. For example, KCP&L could self-commit the same unit for the same test at the same time each year and end up with a different financial result each time based on system topology, weather, etc. at the times of the test.
>
> While KCP&L can't commit to providing that economic impact of self- commitments, the Company can show that its self-commit decisions have been financially prudent over time. The data provided for the [MPSC Order opening GI,] Question No. 6 includes production costs and prevailing market prices for energy that KCP&L had self-committed.[27] ** [redacted] **

<u>KCP&L's Level of Market-Committed Coal Plants & Comparison to Other Coal Units in SPP</u>

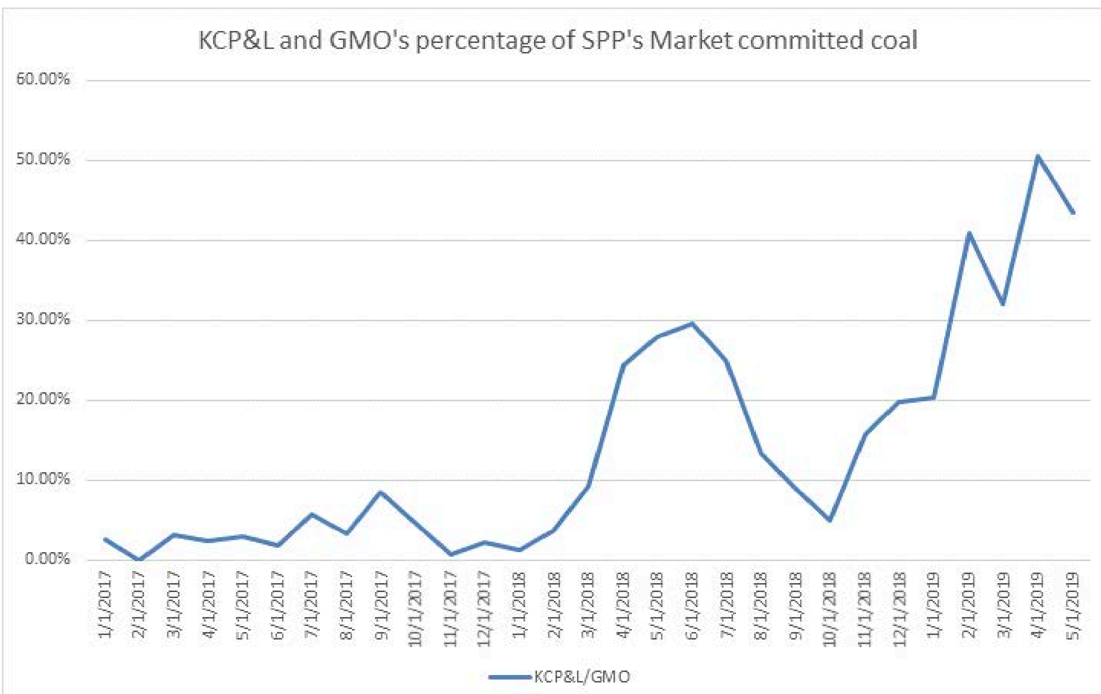
Since 2017, KCP&L offered its coal units in market status 38% of the time when its unit were available.[29] KCP&L continues to progress in its uses of market commitment for its coal assets. In 2017, KCP&L offered its coal unit in market status approximately 31% of the time.[30] By 2018, KCP&L's use of market-commitment increased to 41%, and its use of market status for coal plants

[26] KCP&L confidential response to KCC Discovery Request No.49: Q49_KCPL-GMO Response to Order Directing Filing_CONF_7-8-2019.pdf, pages 1 - 2.
[27] In the Order opening General Investigation, the MPSC directed utilities to provide monthly and annual data to calculate the difference between production costs and corresponding prevailing market prices for energy self-committed.
[28] KCP&L confidential response to KCC Discovery Request No.49: Q49_KCPL-GMO Response to Order Directing Filing_CONF_7-8-2019.pdf, pages 4 - 5.
[29] *See Id*, page 5.
[30] *See Id.*

increased to 48% in 2019.[31] KCP&L noted that one of the drivers of self-commitment of its coal units is the lack of a SPP market process for "economic" commitment across multiple days.[32] The lack of a multiday market is something the entire market (not just KCP&L) has realized and struggled with, and in response, the SPP MWG has included the evaluation of a multi-day unit commitment tool on its list of major initiatives.[33]

In response to KCC Data Request No. 49, KCP&L provided a comparison of its market-committed coal generation against other coal resources in the SPP footprint:

> Compared to generation actually produced in SPP, the graph below shows the percent of Market committed Coal Generation MWh for KCP&L/GMO as a percentage of the total amount of Market committed MWh of Coal generation in the SPP Footprint.[34] This demonstrates that in April of 2019, half of the Market Committed Coal Generation in the SPP Footprint was provided by KCP&L/GMO Coal units running in a Market Commitment status. The trend of KCP&L/GMO's Market Committed Coal Generation is outpacing the SPP footprint as a whole. This point is made more evident when you consider that as of 2018 KCP&L and GMO combined to account for a mere 11% of total Coal Capacity within the SPP footprint, according to SNL. October and November of 2018 saw a large percentage of KCP&L/GMO coal generation unavailable, which helps explain that dip. During this period, the units were unavailable 78% of the time in October and 72% of the time in November.[35]



[31] *See Id.* For 2019 results, KCP&L's calculation percentage for its use of market-commitment of it coal assets includes data through May 31, 2019.
[32] *See Id.*
[33] *See Id.*
[34] Please see the graph of KCP&L and GMO's percentage of SPP's market-committed coal on the following page.
[35] *See* KCP&L confidential response to KCC Discovery Request No.49: Q49_KCPL-GMO Response to Order Directing Filing_CONF_7-8-2019.pdf, page 5.

In response to Staff discovery, KCP&L discusses its process for evaluating the market-commitment of its coal assets. As prices in SPP fell, KCP&L was actively evaluating the risks associated with more frequent cycling of the units. KCP&L continues to pursue the flexible operation of its coal fleet while balancing the operational and maintenance risk from more frequent cycling of the units. In response to KCC discovery, KCP&L stated:

> ** [redacted] **

Furthermore, KCP&L summarizes its advancement in cycling its coal units and discusses how capital projects helped increase the market-commitment of its facilities. In response to Staff discovery, KCP&L provides an overview of its cycling effort stating,

> ** [redacted] **

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[36] *See* KCP&L's response to Confidential Staff Data Request No. 49: MPSC GI: Question No. 3, 08/22/19, page 1.
[37] *See* KCP&L's response to Confidential Staff Data Request No. 50: KCP&L Cycling Investment.
[38] *See* KCP&L's response to Confidential Staff Data Request No. 49: MPSC GI: Question No. 3, 08/22/19, page 1.
[39] *See Id*.
[40] *See Id*, page 2.
[41] *See Id*.
[42] *See* KCP&L's response to Confidential Staff Data Request No. 49: MPSC GI: Question No. 3, 08/22/19. KCP&L provided a breakdown of plant additions and a list of OEM sources it used in evaluating the impact of more frequent cycling of its baseload coal units, which are available on request.

MPSC-Staff Study – Methodology, Findings & Conclusions:

The MPSC-Staff employed considerable resources in its self-scheduling study and evaluated generation offer curves for coal plants across all operating hours for three years. In order to manage the level of data and cost curves, Staff would need access to economic dispatch modeling software to evaluate each variable of the offer curve submitted by KCP&L to determine whether the revenue exceeded the production costs of the unit. As the MPSC-Staff explained, 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-committed economic minimum; and therefore, these variables impact the revenue in excess of generation costs for the unit.[43]

The MPSC-Staff conducted an analysis of the number of hours per month that each unit was dispatched at its economic minimum or must-run status without any additional dispatch under the economic or market status.[44] The MPSC-Staff notes that merely analyzing the number of hours each unit was self-scheduled would not provide a clear picture of whether the decision to self-commit was a good economic decision.[45] If the RTO dispatched the self-committed unit above its economic minimums for the vast majority of its operating hours, a clear customer benefit is demonstrated through the economic operation of the plant as long as the participant is using a cost-based bidding strategy.[46] 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.[47] The MPSC-Staff provides the following example to illustrate this principle. 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, the utility's decision to self-commit the unit may have been a sound economic decision.[48] If a self-committed unit is only dispatched at its economic minimum for a significant number of operating hours during the period, the self-commitment decision could warrant additional research and discovery.[49]

The MPSC-Staff details that the possibility exists of a different market strategy that could increase the benefit to customers through maximization of off-system sales revenue and the minimization of fuel costs.[50] However, it is also possible that a change in strategy might cause customers 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.[51] Based on the MPSC-Staff's review of KCP&L's coal units, the market revenue from energy sales exceeds the production cost of the units in aggregate and contribute to the recovery of the fixed production costs of the unit. Based on its findings, the MPSC-Staff did not make any

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[43] *See* MPSC-Staff Report Investigating Generator Self-Commitment into SPP Generator Self-Commitment in SPP and MISO Day-Ahead Energy Markets, page 13 File No. EW-2019-0370, issued August 23, 2019.
[44] *See Id.*
[45] *See Id.*
[46] *See Id.*
[47] *See Id.*
[48] *See Id.*
[49] *See Id.*
[50] *See Id.*
[51] *See Id.*

ratemaking or prudence recommendations in its report, but the MPSC-Staff plans to monitor the frequency self-committed units are dispatched at their economic minimums without additional market dispatch in future fuel cost audits.[52]

KCP&L's Coal Generation Capacity & MPSC-Staff Analysis of Unit Commitment Data
Over the study period, Staff provided a table of KCP&L's coal generation and its name-plate capacity for reference below.

KCP&L GENERATION: NAME PLATE CAPACITY (MW)						
Generation Facility	**Ownership**	**Ownership Percentage**	**2016**	**2017**	**2018**	**2019**
Iatan	Co-owned	61%	1,055	1,055	1,055	1,055
LaCygne	Co-owned	50%	799	799	799	799
Hawthorn 5	Owned	100%	594	594	594	594
Montrose*	Owned	100%	376	376	376	Retired
***Montrose 2 & Montrose 3 retired December 31, 2018.**						Data: FERC Form 1

MPSC-Staff Report of KCP&L Self-Commitment Data
As discussed, the MPSC-Staff evaluated the self-commitment and self-scheduling practices of Missouri's coal fleet by examining KCP&L's entire generation bid to evaluate whether generation revenue exceeded the production cost of each coal unit. In addition to examining the various components of the offer curve and generation revenue, the MPSC-Staff examined the hours that the units were self-committed and number of hours dispatched at the unit's economic minimum. The confidential findings provided by the MPSC-Staff are included in the detail below. Staff will provide its own review of aggregated data following the MPSC-Findings.

Confidential Findings by the MPSC-Staff on KCP&L's Offers
In working with KCP&L's self-commitment data and offer curves for its coal units, the MPSC-Staff noted a few key items.

- ** [redacted]
    - [redacted]

[52] *See Id.*
[53] *See* Confidential MPSC-Staff Report: Appendix A: Analysis of KCP&L's Self-Commitment Strategies, page 5, filed on August 23, 2019, in Docket No. EW-2020-0033.

[redacted]

- [redacted]

[redacted] **

MPSC-Staff Report – KCP&L Monthly Settlement Data

The MPSC-Staff prepared the following four schedules using KCP&L's self-commitment data provided in data request responses. Staff has attached the Schedules Nos. 1 – 4 with the monthly self-commitment data in Appendix A to this Report. Staff will discuss the data contained in the Schedule and reference key findings by the MPSC-Staff in its review of KCP&L's data. Staff will included aggregated yearly data for each Schedule in Staff's Analysis following the MPSC-Staff findings.

- Schedule 1 contained the calculation of KCP&L's revenue in excess of generation costs for each coal unit on a monthly basis over the three-year period June of 2016 through June of 2019.
  - ** [redacted] **
- Schedule 2 showed the amount of MWhs that cleared in the day ahead market when unit was self-committed on a monthly basis over the study period.
  - ** [redacted] **

[54] *See Id.*
[55] *See Id.*
[56] *See Id.*
[57] *See Id*, page 6.
[58] *See Id*

- Schedule 3 contained a table showing the number of self-committed hours for each coal unit on a monthly basis during the study.
  - ** [redacted] **
- Schedule 4 contains a table showing the number of self-commit hours each unit ran at the economic minimum level.
  - ** [redacted] **

<u>General Findings and Conclusions by the MPSC-Staff</u>

The MPSC-Staff report provided the following general conclusions based on its unit-by-unit analysis of KCP&L's self-commitment data,

** [redacted] **

Based on its findings, the MPSC-Staff reaffirmed that its investigation had not found any evidence that customers are actively being harmed by the IOU's market strategies for self-committing its

[59] *See Id.*
[60] *See Id.*
[61] *See Id, page 7.*

coal units, since the revenues from the self-committed units exceed the production costs of the units. Therefore, the MPSC-Staff finds the costs should subsequently flow through the FAC-Rider tariff.

Aggregated Self-Commitment Data & Staff Findings and Recommendations

In this section, we provide a summary of the aggregated monthly self-commitment data by coal unit compiled from Schedule No. 1 through Schedule No. 4, which can be found in Confidential Appendix A attached to this Report.[62]

** [redacted]

[redacted]

[redacted]

[62] *See* Confidential Appendix A; Schedule No. 1 through Schedule No. 4 for KCP&L's monthly self-commitment data by coal unit from June of 2016 through June of 2019.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **

Staff Finding and Conclusions

In our review of KCP&L self-commitment practices, Staff did not find any evidence that KCP&L's market strategies for managing its coal units harmed Kansas ratepayers. In aggregate, during the hours that the units have been self-committed, all of the KCP&L coal-fired generators have produced margins in excess of its short-run productions costs over the unit's long-term operations. Staff contends that coal-fired generation units must be effectively managed over the long-term operation of the asset to support the safe and reliable operation of the unit and maintain long-term profitability of the assets. Staff contends that disallowances for uneconomical dispatch should only be considered if the medium or long-term operations of the unit results in an uneconomic outcome for ratepayers. As such, Staff is not recommending any disallowances based on our review.

The MMU Whitepaper clearly demonstrated that the current unit commitment logic is insufficient to effectively commit and dispatch coal units due to their long lead-times. Therefore, KCP&L should continue the active long-term management of its coal resources to the benefit of customers and avoid operating in uneconomic periods when possible. In future ACA audits, Staff will issue discovery to evaluate KCP&L's coal units on a monthly-basis to compare the average market prices for energy sales against the production cost included in a mitigated offer when the unit was self-committed.

If KCP&L can accrue benefits for ratepayers by reducing the output of its coal units during uneconomic operating periods or operating its coal units seasonally, Staff's recommendation is that KCP&L should continue to explore these opportunities (even if this results in a reduction to the units' capacity factor). Lastly, the long-term economic viability of KCP&L's coal units should continue to be evaluated through normal planning processes, including the Triennial IRP Docket.

Maximizing the long-term value of each coal asset is in the best interest of ratepayers as it allows KCP&L to increase the capacity factor at its most efficient units and decrease the capacity factor at less efficient units, thereby reducing production costs. Additionally, KCP&L should be free to purchase low cost power from market resources when market prices cannot support a coal unit's production costs. This could reduce the operating, maintenance, and capital maintenance costs at certain units resulting in increased ratepayer savings.

RECOMMENDATION:

Staff recommends that the Commission approve KCP&L's Application authorizing the use of its 2018 ACA factor of $0.00108 per kWh. Staff will continue to monitor KCP&L's performance and participation in the IM and will provide periodic updates to the Commission regarding this issue as often as is desired.

REDACTED APPENDIX A:
SPP IM Activity for KCP&L's Coal Units
Schedules Nos. 1 – 4

Contents Page No.

[redacted]

[redacted]

[redacted]

[redacted]

SELF-COMMITMENT REPORT: APPENDIX B

Self-Commitment of Baseload Coal-Fired Generation

As stated in the Report & Recommendation, Staff included the general portions of its Self-Commitment Analysis in Sections I through Section V in Appendix B. For reference, provided herein is an overview of the five sections of analysis contained in Appendix B.

I. Overview of the SPP Integrated Market (IM): Staff discusses the SPP IM structure and details the market processes responsible for minimizing production costs throughout the SPP footprint. This discussion reviews the five unit commitment statuses available for generators in SPP and details SPP's processes for setting the marginal energy price, determining resource dispatch, and generating locational pricing. Then, we explore the market incentives and market feedback mechanisms that drive the decision-making processes of market participants. Finally, we discuss how the economic and operating parameters of generating units drive the market interactions of resources with varying fuel types and detail how changes in the costs of fuel influence resource selection.

II. Market Function and Use of Self-Commitment by Kansas Utilities: Staff discusses the market function and use of self-commitment in energy markets. Then, we detail the market factors that contribute to the self-commitment of coal-fired generation in SPP. Next, we review Kansas utilities' practices for self-committing their coal-fired units. This review outlines market scenarios that lead to the self-commitment of coal units and explains the risks that are mitigated by the self-commitment of the unit. Finally, Staff provides its own analysis of market factors that drive the self-commitment of coal units and the operators' general objectives in managing unit commitment.

III. Effects of Self-Commitment in Energy Markets: Staff examines the market effects of self-committed generation in energy markets and explains how self-committed units alter the generation supply curve and resource dispatch. Then, we discuss how the current SPP market design contributes to the self-commitment of coal-fired generation. Finally, we discuss the impact of self-commitment on the marginal energy price, merit-based dispatch, pricing and investment signal distortion, and negative pricing intervals.

IV. Market Monitoring Unit (MMU) Whitepaper - Empirical Analysis and Simulations: Staff overviews the findings from the MMU's empirical study of market participants' offer behavior and details trends in the level of self-committed generation in the SPP IM. Then, we discuss the MMU's analysis and recommendations included in its Annual State of the Market Reports. Finally, we overview the MMU's market simulations studying two self-commitment scenarios. For each scenario, the MMU resettled the market to quantify the impact on marginal energy prices and regional production costs in SPP. In our review, we detail the MMU's study methodologies, examine the market impact of each settlement scenario, and discuss the MMU's recommendation to explore a market design enhancement for a multi-day unit commitment optimization.

V. Review of Sierra Club Studies: Staff provides a high-level overview of the self-commitment studies released by the Sierra Club in 2019. Then, we provide a detailed review of the Sierra Club's study entitled, "Kansas Pays the Price," that purports to quantify the ratepayer impact of Evergy's three large Kansas coal units. In the study, the Sierra Club calculates the market revenue from energy sales for each coal unit and compares the revenue against the unit's fuel and variable production costs plus the fixed operating, labor, and maintenance expenses. Following the revenue and cost review, we discuss the Sierra Club's recommendations to limit ratepayer exposure to the uneconomic operation of coal resources. Finally, we discuss our view of the Sierra Club's research and detail our differences of opinion with the Sierra Club's analysis.

I. Overview of SPP IM

The SPP IM launched in March of 2014, replacing the previous Energy Imbalance Service (EIS) market. The SPP IM features a Day Ahead (DA) and Real-Time Balancing Market (RTBM) for energy and operating reserves. The vast majority of energy and operating reserves are cleared in the DA market. The RTBM acts as a balancing market to clear deviations between the projected generation supply and load demand and actual real-time activity. The DA market allows buyers and sellers to avoid the price volatility of the RTBM by locking in projected generation sales and load purchases for the next operating day. The DA Market is settled hourly at each price node while the RTBM settles in five-minute intervals. Both markets are financially binding on market participants. SPP issues multiple forecasts for system demand and forecasted wind output to aid market participants in projecting its day-ahead generation supply and retail load demand accurately.

The primary purpose of the SPP IM design is to minimize the production costs to serve regional load without violating any generation or transmission constraints. The MMU Whitepaper further explains that the function of the market software is to minimize the production cost not the marginal clearing price.[1] Production costs are defined as the sum of energy,[2] ancillary reserves,[3] start-up,[4] and no-load costs.[5] The market-clearing price is an output of the market optimization process and is only one component of the total production cost. Increases to the clearing price may not result in increases to the production costs. In order to minimize production costs, the DA market uses two primary tools: centralized unit commitment and economic dispatch. The unit commitment optimization starts by sorting the generation according to corresponding price curves submitted by market participants and then, selects the least expensive units to serve the system demand.[6] Using the output of the centralized unit commitment, the economic dispatch optimization runs a secondary optimization process to produce the megawatts each generator should produce at corresponding locational prices.[7] These two processes are designed to work

[1] Marginal energy prices are determined by identifying the cost to serve the next incremental load at a specific interval and location.
[2] Energy is power flow over a time-period.
[3] Ancillary services are needed to maintain reliability of the system, often by forgoing the opportunity to sell energy.
[4] Start-up is the cost associated with preparing a generator to produce and stop producing energy and operating reserves.
[5] No-load is the theoretical cost of running a generator while producing no output.
[6] Centralized unit commitment uses a security constrained unit commitment (SCUC) algorithm capable of committing resources to supply energy and operating reserves on a co-optimized basis that minimizes the commitment costs while enforcing multiple security constraints.
[7] Economic dispatch uses a security constrained economic dispatch (SCED) algorithm capable of clearing, dispatching, and pricing energy and operating reserves on a co-optimized basis that minimizes overall cost while enforcing multiple security constraints.

together to make the market more efficient and are essential to minimizing the production costs across the SPP regional footprint. The processes are driven by the market participants' selection of a generator commitment status and the submission of a supply curve for their operating units.

Generator Commitment Statuses in the SPP IM

Under the SPP IM protocols, a market participant must elect a unit commitment status for each of its operating units. The five commitment statuses that a market participant can elect are: (i) Market; (ii) Self; (iii) Reliability; (iv) Outage; or (v) Not participating. Each status conveys different information to the SPP market-clearing engine for centralized unit commitment and economic dispatch purposes. The "market" status is elected when a resource is online and available for dispatch based on its energy offer curve. Market-committed resources are cleared and dispatched based on merit through SPP's unit commitment and economic dispatch processes. A market participant will elect the "self" status when a unit is available for production through a price insensitive offer. Self-committed and self-scheduled resources[8] clear outside the centralized unit commitment process and receive the marginal energy price for output.

In periods of low demand, self-committed resources may not recover the unit's short-run production costs incurred to operate the generation unit. Market participants can elect to self-commit a unit up to the unit's economic minimum operating parameters. When self-committed units are dispatched above their economic-minimum, the units are evaluated based on the unit's price curve. The "reliability" status is elected when the resource is offline and only available if there is anticipated reliability issue. The "outage" status is elected when the resource is offline and unavailable due to a planned, forced, maintenance, or other approved outage. The "not participating" status is elected when the resource is available, but has elected not to participate in the DA market.

Unit Commitment – Setting the Marginal Energy Price

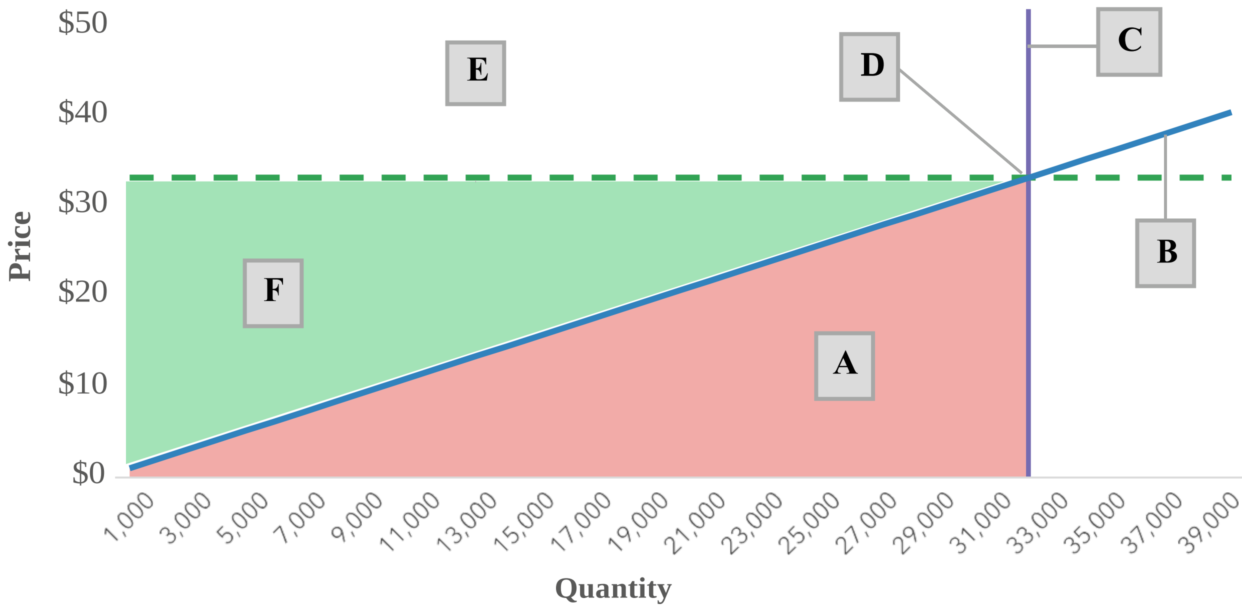
Energy markets are structured similarly to a reverse auction where generators compete to meet the regional energy demand. In auction-based markets, market participants recoup the short-run marginal costs including fuel, other variable production costs, and short-term maintenance in their energy offers. Generally, the fixed production costs and capital costs are recovered through operating margin produced from the sale of the asset in the market or recouped from retail ratepayers in utility rate cases. The DA market begins with the market participants electing a commitment status for each generator and submitting an energy offer curve for each unit. The energy offer curve represents the price per quantity of output that the unit is willing to provide to the marketplace, and the curve is based on the short-run variable cost of operating the unit. The offer curve is stated in dollars per megawatt-hour ($/MWh) and submitted as a sloped line (sloped curve), a stepped line (block curve) or a flat line. With the submission of generator offers, market participants that are load-serving entities will forecast and bid into the market its expected energy demand for day-ahead load locations. Market participants must provide this information for each hour of the day at each of its generator and load location. The market-clearing engine runs an optimization process to sort resource offers and clear the units with the lowest cost to meet the

[8] Self-scheduled resources block load their offer curve by submitting one-point offer curves, where economic dispatch range is zero, i.e. where economic minimum and economic maximum values are identical.

regional energy demand.[9] The most expensive unit cleared becomes the marginal resource and sets the price of energy across the region. The marginal energy price is paid to all resources regardless of the resource's offer and is incorporated into one of the components of the LMP. Finally, resources committed by SPP for economic or reliability purposes are eligible for make-whole payments.[10] Make-whole payments ensure resources that are cleared through market processes recover their eligible operational costs over the commitment period. If the market revenue for the resource falls short, SPP will issue a make-whole payment distribution for the eligible unrecovered production costs.

The MMU whitepaper provided an example of setting a marginal clearing price based on the supply and demand in the marketplace.[11] The MMU analysis is presented in economic terms that have very precise and specific meanings. For this reason, Staff provided a reproduction of the chart and its explanations below.

SPP IM – Market Supply and Demand[12]



A. The red shaded region is production cost,[13] more specifically the energy portion of the total production costs.[14] This region is also referred to as the area under the supply (or marginal cost) curve, which gives total variable costs, or total marginal costs.

B. The supply curve is the blue line. In electricity markets, the supply curve is created by summing the offers of market participants. These offers are submitted in price/quantity pairs each

[9] The SCUC algorithm is capable of clearing resources and/or operating reserves on a co-optimized basis that minimizes capacity costs and enforces multiple security constraints.
[10] The SPP market offers a Make-Whole Payment guarantee that allows generating units ***started by SPP*** to receive enough revenue to cover their three-part offers (Energy, No-load, and Start-up Offers) and Operating Reserve Offers. If SPP dispatches a resource, the market provides a make-whole payment distribution to compensate the unit for unrecovered production costs, essentially holding the market participant harmless for revenue deficiencies.
[11] See MMU Whitepaper: Self-committing in SPP markets: Overview, Impacts, and Recommendations, published December of 2019, pages 17 - 18.
[12] *See* MMU Whitepaper, Figure 3-2: Market Supply and Demand, page 11.
[13] Corresponding to "mitigated offers" in SPP tariff terms.
[14] Production costs is generally presented as the sum of energy, start-up, no-load, and ancillary service costs.

indicating minimum price levels the supplier is willing to offer for the corresponding quantity. The price the supplier wants to be paid is plotted on the y-axis, and the quantity the supplier is willing to pay is plotted on the x-axis.

C. The demand curve is the purple vertical line.[15] The demand curve shows price/quantity pairs each indicating the maximum price levels the consumer is willing to demand for the corresponding quantity. Electricity is mostly a non-storable product and must be supplied instantly upon demand. Further, when there is competition at the retail end, price elasticity is very low. As such, the demand is represented as a vertical line.

D. The market-clearing price is the point where supply meets the demand. When this occurs, all buyer orders have been filled and the market is said to have cleared. In an organized wholesale electricity market setting, the market-clearing price is called the spot price.

E. The dark green dotted line reflects the price each supplier is paid and is equivalent to the market-clearing price. This equilibrium price multiplied by total quantity produced is the revenue received by all suppliers.

F. The light green shaded region is the producer surplus. Generally, when economists refer to profit, they are referring to the producer surplus. Short-run profits for individual producers can be calculated by subtracting variable costs from revenue where revenue equals market-clearing price multiplied by quantity produced.[16]

<u>Economic Dispatch & Locational Pricing</u>

Following the unit commitment process, the market-clearing engine will run a secondary optimization that dispatches resources and produces LMP or marginal clearing price at each of the pricing nodes across the SPP regional footprint.[17] Economic dispatch is the short-term determination of the optimal output of a number of electricity generating facilities, to meet system load, at the lowest possible cost. The LMP represents the marginal cost of serving demand at the pricing node. The LMP is made up of three primary components: the marginal energy component (MEC), the marginal congestion component (MCC), and the marginal loss component (MLC). While the LMP varies between nodes, the MEC is identical for each pricing node in SPP. The LMP price differential is driven by congestion costs (MCC) and line losses (MLC).

In the Annual State of the Market Report for 2018, the MMU calculated that 75% of the price variation in LMP was driven by congestion costs while 25% was applicable to marginal losses.[18] Congestion costs are related to the physical system constraints of the transmission system. Congestion costs are assessed to both generation and loads. Generators are charged congestions through reductions in the LMP, and loads are charged through increases in the LMP. The MLC is the smallest component of the LMP and accounts for transmission line losses at the locational

[15] This represents perfectly inelastic demand. Under that assumption, demand is not responsive to price. In practice, the line may not be vertical, having a certain degree of downward slope depending on the degree of price responsiveness in the market, particularly in the DA market.
[16] In electricity markets, startup and no load costs, in addition to incremental energy costs need to be included in short-run profit calculation.
[17] SCED algorithm is capable of clearing, dispatching, and pricing energy and operating reserves on a co-optimized basis that minimizes overall costs and enforces multiple security constraints.
[18] *See* SPP Annual State of the Market Report for 2018, page 155. The LMP price variation split of 75% related to congestion costs and 25% related to marginal losses is consistent with past State of the Market Reports.

pricing node.[19] Line losses occur for a variety of engineering factors and vary based on the line's voltage and temperature of the surrounding environment. The MLC is calculated by multiplying the MEC by the Marginal Loss Sensitivity Factor (MLSF) at the defined pricing node. The MLSF are dependent on topology, node injection and node withdrawal.

Market Efficiency and Pricing Signals

The structure of the marketplace fosters competition among generating resources through centralized clearing process, and this competition drives efficiency in the marketplace through the minimization of production costs. Market participants are incented through market design to pursue resources that minimize the production costs to serve load. Units with lower variable costs will have a greater opportunity to both clear the unit commitment process and will receive more margins per unit of output than resources whose production costs are closer to the marginal clearing price. As units that are more efficient enter the market, the resources compete with existing resources. If an existing resource were no longer competitive in the wholesale markets for energy and operating reserves, the resource would be slated for retirement barring any concerns with system reliability.

Energy markets rely on a feedback mechanism to direct the decision-making process of the market participants. Resource offers are crafted with the continuous goal of maximizing profits in the short-run. In the long-run, market participants analyze the current market trends to inform the decision-making process for investment in future generation capacity or to retire aging infrastructure. As new entrants enter the market, the existing generation resources adapt to a new market equilibrium. This constant pursuit of a short-term and long-term market equilibrium creates a market feedback loop.[20] The MMU provided an illustration of the Market Feedback Loop in figure 3-1 of the MMU Whitepaper.[21]

The feedback loop begins with the market participant's submission of resource offers for current installed capacity. The submission of the market participants' offers drives the centralized commitment and economic dispatch optimization, and the market optimizations drive market pricing and resource dispatch. Market pricing and resource dispatch drive market participants to modify short-term market strategies or install/retire generation capacity over the long-term. Market participants' decisions to install or retire capacity affects the existing capacity in the market and drives the submission of future offers.

Generation Constraints and Fuel Pricing

Unit commitment decisions can be driven by the underlying operating and economic parameters of the generating resource. Generally, these parameters are consistent across resources with similar fuel types. A unit's operating parameters tend to be physical or time-based operating limitations, such as ramp rates, minimum run times, and lead-times, whereas economic parameters include the cost of fuel, start-up costs, variable operating expenses, and fixed costs. The operating parameters tend to govern the interaction of the resource within the marketplace. A resource's

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[19] The MLC_i is the component of LMP_i representing the marginal cost of losses at Pricing Node (PNode) relative to the Reference Bus. The MLC is calculated by applying the MLSF at the $PNode_i$ to the Marginal Energy Component.

[20] *See* the MMU whitepaper, page 9.

[21] *See Id*, Figure 3-1: the Market Feedback Loop, page 10.

lead time, minimum run time, minimum down time, or ramp rates will act as operating constraints for the resource in the unit commitment and economic dispatch process. Quick ramping resources may be highly reactive to market pricing signals allowing the units to take advantage of fluctuation in renewable resource output. In recent years, the flexibility of resources to quickly respond to market pricing has become an increasing important variable due to the level of renewable generation that have been added to the system SPP system.

Generation units have trade-offs that govern the underlying economics of operating the unit. Generally, there is an inverse relationship between fuel expenses and fixed expenses/capital expenditures necessary to operate the facility. Assets with low variable fuel costs tend to be more capitally intensive to construct and maintain while resources with higher fuel costs tend be less capital intensive resulting in lower fixed costs. The benefits or detriments of high operational leverage can be dependent on the relative cost of fuel when compared to resources with alternative fuel sources. While fuel market pricing is driven by the supply and demand for the underlying commodity, fuel markets are interdependently tied together. For instance, the supply and demand of natural gas can alter demand for other fuel sources. When compared to other fuels, natural gas pricing tends to have the most direct link to pricing in the wholesale energy market. Furthermore, demand for wholesale energy for heating and cooling influences the price and availability of natural gas. Energy demand in peak operating season impacts the availability of the natural gas supply causing wholesale energy prices to spike. The interdependent relationships between fuel markets and wholesale energy markets are complex and vary significantly between regions. Diversification of the generation fuel mix allows energy markets to avoid fuel price spikes by substituting another fuel source.

<u>Generation Fuel Type – Market Advantages and Disadvantages</u>

A generation resource's fuel-type can result in certain market advantages and disadvantages. Renewable resources benefit by having no fuel cost and low variable operating expenses. These resources will receive more operating margin per unit of output than units whose fuel costs put them closer to the market-clearing price, but the trade-off for wind and solar units is intermittent capacity that is unresponsive to energy demand. Renewable resources are incented to produce energy whenever the environmental factors allow the unit to be operable in order to recover the fixed capital cost of the asset. Unit curtailments are impacted by the generation supply surplus and energy demand in the marketplace. If frequent unit curtailments occur, it can affect the resource's ability to recover its fixed capital costs and hinder development of future renewable resources. In SPP, the competition between wind resources and inflexible baseload units can apply downward pressure on the wholesale energy price or increase the frequency of negative pricing intervals.

In contrast, fossil fuel plants produce a lower level of operating margin due to generator's fuel costs, but fossil fuel units have the capability to respond to energy demand when called upon by the market. A fossil fuel unit's ability to respond to energy demand and market pricing varies significantly by fuel type. Coal units were designed and traditionally operated as baseload resources that produced energy and operating margins around-the-clock. Continuous operating margins allowed coal facilities to recover the fixed operating and maintenance expenditures of the unit plus a greater degree of capital investment to construct the unit. As baseload resources, coal units were not engineered to respond rapidly to changes in energy demand requiring longer lead times to alter the energy output of the unit. Coal plants must also contend with higher start-up costs and operating constraints that impact the resource's availability. The primary advantage of these resources was a significantly lower cost of fuel with less volatility than natural gas resources. Historically, the availability of natural gas during high demand seasons significantly increased the wholesale energy prices paid to generators. Peak energy demand required integrated utilities to dispatch peaking plants that relied on spot-purchases of natural gas driving up pricing in the wholesale energy markets. When wholesale energy prices were elevated due to the higher underlying price of natural gas, coal resources with lower fuel cost generated a significant revenue stream during summer and winter peaking seasons. As the price of natural gas fell and renewable generation entered the market, the wholesale energy price decreased substantially in SPP, which affected the operating margins generated from coal resources during peak demand seasons. Finally, coal resources have experienced significant increases in the variable cost of fuel to comply with environmental compliance and air quality standards. Environmental control equipment required water and various chemical reagents that increased variable production costs and introduced parasitic load to run the auxiliary equipment.

Compared to coal units, natural gas resources have a lower degree of operational leverage requiring less intensive capital investment to construct and maintain the asset and lower levels of labor costs to operate the resource. In exchange for less fixed costs, the economic trade-off for the gas units has historically been higher fuel costs and increased exposure to fuel price volatility. A significant advantage for gas units is their overall responsiveness to energy demand allowing the resources to follow market-pricing signals effectively. Natural gas units are able to cycle the unit without incurring a high-level of start-up costs. Lower lead-times and faster ramp rates allow gas units to respond quickly to pricing fluctuations in the wholesale energy market. Due to this quicker response rate, natural gas units are more adept in dealing with the output uncertainty of renewable energy resources and can quickly start-up or ramp to fill in gaps if wind speeds drop. Currently, natural gas resources are competitive with coal units due to the units lower start-up cost and the relatively low price of natural gas. Finally, natural gas units dispatched by the market qualify for make-whole payments ensuring cost recovery for qualifying production costs under the Make-Whole Provisions of the SPP tariff.

<u>Market Impact from Renewable Generation and Natural Gas Infrastructure Investment</u>
Investment in renewable generation and the supply of natural gas has resulted in lower pricing for wholesale energy in RTO markets. In recent years, renewable generation development has increased exponentially in SPP with targeted infrastructure development in wind rich regions of the footprint. The development of renewable generation has been incentivized through investment tax credits and Renewable Energy Standards passed by state legislatures—two factors that have not been linked to underlying changes in energy demand. Investment tax credits were structured to provide credits based on the quantity of production output from the facility, which incents these generating units to run when capable.

Along with the development of renewables, capital investment in oil and natural gas infrastructure in the United States increased substantially due to horizontal drilling methods opening up shale deposits across the United States. The resulting increase in the national output of oil and natural gas has reduced the natural gas price and lowered price volatility. While natural gas remains a particularly volatile commodity in periods of high demand, the increased natural gas production has helped gas resources to be more competitive in periods of low demand and tempered the volatility in peak seasons of demand. With the mix of lower priced natural gas and more renewable generation, SPP's wholesale prices have flattened in summer and winter peaks. Due to the increase in excess generation capacity, baseload coal units had to contend with low or negative pricing intervals in off-peak hours and shoulder months or elect to cycle the unit. Integrated utilities began to investigate the effects cycling has on the long-term availability of the plant. As wholesale energy prices in SPP declined, integrated utilities began testing whether its baseload resources could be effectively cycled to lower costs for retail ratepayers.

This section was meant to review the foundational principles of energy markets and describe market forces contributing to the self-commitment of baseload resources. Understanding these principles provides a foundation to understand the decision-making processes of utility operators when evaluating unit commitment. Understanding how resources interact and how generation investment influences market pricing provides the necessary context for examining the market effects of self-commitment. Rapid increases in renewable generation investment and shifts in fuel pricing can have significant impacts on existing resources in the SPP IM. The next section focuses on the role self-commitment plays in the SPP IM and examines the use of self-commitment by Kansas utilities to manage coal resources.

II. Market Function and Use of Self-commitment by Kansas Utilities in the SPP IM

The ability to self-commit or self-schedule[22] generation resources serves an important market function in wholesale energy markets administered by RTO/ISOs. Functionally, self-commitment allows market participants to control when a generating unit operates. While any generation type can be self-committed, coal-fired units are responsible for the largest portion of self-committed megawatts in the SPP IM. Coal-fired units tend to have a greater degree of operating leverage (marginal costs/fixed cost) than other generation assets. Margins generated from incremental sales help contribute to the fixed costs recovery of the asset. Each incremental sale that produces operating margin lowers the fixed cost that is attributable to the next incremental sale. The higher the operating leverage the more profit[23] earned from an incremental sale and the greater the opportunity cost from a lost sale. Utilities rely on operating margins to support fixed cost recovery. Generally, integrated utilities do not submit major maintenance expenses in its resource offers, and these costs are not reflected in the LMP in SPP. Major maintenance expenses include mid-term maintenance performed at standard, industry-recommended intervals on essential components of the unit. If a utility reflected the major maintenance expenses in its resource offers, the resource offer submitted for the unit would be less competitive to other market resources. If the deviation in the resource offer was significant, the unit's ability to clear the unit commitment optimization may be materially impacted, or SPP may find the utility exercised "market power[24]" through economic or physical withholding resulting in the offer being mitigated.[25]

[22] Self-scheduling a resource is similar to electing to self-commit an asset; however, self-scheduling allows a market participant to control both when the unit operates and the exact quantity of output for the unit by submitting a block-loaded offer curve consisting of a single point. The MMU found that self-scheduling accounts for roughly 6% of the total self-commitment volume.

[23] Short-run profit or operating margin.

[24] Market Power is the ability for a utility to cause prices to deviate from competitive levels by controlling the provision of generation capacity or transmission capacity to the market, whether by "physical" withholding or "economic" withholding.

[25] SPP provides mitigated offer guidelines can be found in Appendix G of the Integrated Marketplace Protocols.

While some RTO/ISOs, like Midcontinent Independent System Operator (MISO), allow for the recovery of midterm maintenance expense in a resource offer, market participants in SPP cannot include these costs in resource offers. As of January 15, 2019, market participants are allowed to include major maintenance costs associated with the number of unit starts and run hours in a generating resource's mitigated start-up and no-load offers, respectively. In FERC Docket No. ER18-1632-001, SPP acknowledged in its filing of tariff revisions that the inclusions of major maintenance expenses will not affect the LMP or the market-clearing price and only allows market participants to recover documented scheduled maintenance costs when mitigated offers are applicable.[26] SPP considers major maintenance expense to be tied to resource starts and/or run hours, and therefore, it is not a direct component of VOM in the tariff.

The start-up and no-load offers are used in two areas of the SPP IM: (i) the calculation of the total production costs for determination of commitment of resources, and (ii) the determination of whether a make-whole payment is due to the resource. Self-committed resources typically have higher start-up costs that often act as barrier to being cleared by the market-clearing engine and are ineligible for make-whole payments. These subtle differences in market design can highly influence a market participant's decisions regarding unit commitment and influences the cost recovery methodology in RTO/ISO.

<u>SPP's Unit Commitment Process – Operating Constraints and Start-up Offers</u>

The function of the unit commitment software is to evaluate generation offers while taking into account various resource constraints to minimize the production cost of serving retail load. The software co-optimizes both the time-based and economic parameters of resources to determine three primary objectives: (1) is the unit available for production; (2) is the unit operationally capable of providing the market function; and (3) select the resource that fulfills the first two objectives at lowest possible cost. Time-based parameters, such as a long-lead time, are viewed as operating constraints by the commitment software. During the optimization process, a unit with time-based operating constraints could be prevented from clearing the unit commitment process even if the unit's offer was below the marginal resource that was cleared by the market. Market participants are allowed to provide three different lead times, including cold, intermediate, and hot, which aids the market software in clearing units with longer lead times. Lead times vary widely by fuel type. Coal-fired units tend to have the longest lead time, which for some resources can exceed 32 hours from a cold start.

Startup offers represent the cost incurred by a market participant to bring a unit from an off-line state to its economic minimum and includes the cost to shut the unit down. Coal-fired resources have higher start-up costs than other generation types. While start-up offers are submitted in terms of dollars per start, the model evaluates the costs in dollars per start per hour over the lesser of the generating unit's minimum run time or the number of hours from start time through the end of the

[26] *See* Submission of Tariff Revisions to Implement a Major Maintenance Cost Component to Mitigated Start-Up Offer and Mitigated No-Load Offer in Docket ER18-1632-001, filed May 15, 2018, page 2; https://www.ferc.gov/sites/default/files/2020-05/E-9_48.pdf.

day-ahead market window.[27] Given that coal-fired resources also have longer lead times, the start-up costs are optimized over a lesser number of hours. Resources with long lead times will not be online and available to generate energy in hour one of the market and likely will not be available until later in the operating day, which compounds the problem for coal-fired resources. Most resources with high start-up costs have minimum run times that extend past the day-ahead market window. If the market model optimized the resource over the unit's minimum run time, the start-up offer would be more competitive to resources with shorter lead times.

Economic Minimums for Self-committed Units

A market participant can only self-commit a resource up to the unit's economic-minimum operating threshold. A unit's economic-minimum operating thresholds is set by the market participant based on the physical limitation of the plant or its components. The economic-minimum thresholds are set to a level that supports the continuous, safe, and reliable operation of the unit. The economic minimum for each unit is submitted by market participants with the unit's resource offer, and SPP honors the economic-minimum submitted for each unit. Self-committed units can be curtailed beyond the unit's economic-minimum by SPP operators for reliability purposes only. Market participants are allowed to revise these thresholds as needed. Typically, operators revise the economic-minimum based on a reliability assessment, which considers multiple factors such as, weather, past reliability issues, and/or component failure under certain conditions. In any low load scenario, the unit will not be operating within the optimum range of its baseload design, but the key concept is too minimize the risk of component failure and allow for the sustained, long-term operation at the specified minimum. Operationally, utilities may pursue alternatives for low load situations by conducting engineering analysis and low load testing prior to operating the unit below its economic-minimum operating thresholds.

Generator Self-Commitment Factors

Based on utilities' responses to discovery requests, Staff found that utility operators consider various factors in determining a commitment status for a coal-fired unit. Based on these responses, the self-commitment of coal-fired generation generally fit into one of the following categories: safety, reliability, economic, environmental testing, and unit testing following a scheduled or un-scheduled outage or scheduled maintenance on its components. In certain situations, self-committing a unit may be unavoidable. When a unit is self-committed by market participants for either safety/reliability, environmental compliance testing, or unit testing following an outage, the purpose of the self-commitment is more situation-specific and limited in nature. For example, environmental compliance testing is required to comply with regulatory standards for plant emissions or air quality standards, which become a normal operating cost of coal-fired generation. In other situations, the utility may use its operational experience to evaluate whether cycling the facility under certain conditions could lead to issues with the long-term reliable operation of the plant and its equipment. Utilities will also self-commit a unit for economic purposes, which is primarily driven by the current limitations of the unit commitment optimization in the SPP market model. The market model is not equipped to evaluate unit commitment outside of the DA optimization window and fails to dispatch baseload units with long lead times and high start-up costs. Absent self-commitment, the centralized unit commitment process may not dispatch these

[27] The day-ahead market window covers two days. The market software optimizes the DA market over this two-day market window, but only the first day from the unit commitment solution is fed into the economic dispatch model, which results in a financially binding day-ahead market solution.

resources accordingly. Both the MMU whitepaper and the Holistic Integrated Tariff Team (HITT) recommended that a multi-day unit commitment logic be evaluated by stakeholders as a future marketplace enhancement for the SPP IM.

Self-commitment for Safety/Reliability Purposes

As detailed in the discovery responses, utilities may self-commit their coal units to maintain their safe operation and/or protect the units' operational integrity, which lowers the risk of component failure and long-term maintenance costs while preserving the resources' availability to meet future consumer demand. Generally, utilities rely on their system operators to evaluate the operational risk of cycling their coal resources under the forecasted market conditions. System operators assess the risk of component failure based on the operational history of the resources while accounting for external environmental factors, such as cold or inclement weather that could threaten the units' long-term reliable operation. If the risk of component failure and/or cost of the components are significant, utilities may elect to self-commit their coal units to preserve their operational integrity. During cold weather events in Kansas, power plant equipment is vulnerable to freezing. Self-committing a unit in this situation prevents future reliability issues resulting from frozen water lines, oil systems, and coal inventory.

Furthermore, coal-fired generating units undergo a thermal cycling process when the units are brought online or offline, which produces extreme pressure and temperature stresses on the units' components and increases the chance for equipment damage. By managing the number of thermal cycles, the operator protects the equipment and reduces the chance for unreliable starts and unplanned outages. The impact of forced outages, component failure, and shortened component life would significantly influence long-term O&M expense and capital costs in rate case proceedings. Additionally, more frequent cycling shortens the inspections timeframes on valuable components of the coal unit, which are based on the baseload operation of the facilities. Certain inspection intervals such as field windings would need to be performed once every five years compared to the current ten-year interval. Generator inspections require four weeks and cost around $1.0 million. Ratepayers may also be negatively impacted in ECA proceedings by both the loss of foregone operating margins and increases in purchase power expense due to plant availability. Currently, the long-term cost impacts of cycling coal-fired generation are difficult to estimate due to the lack of any long-term operational history for cycling coal-fired units. As a result, utilities project the long-term impact of cycling based on its own operational knowledge of the facilities; component failure history; component manufactures specifications; and scheduled maintenance intervals. Based on its operational knowledge, utilities can effectively manage the long-term reliability of its coal-fired generation by cycling the unit when the risk of component failure is low. If the potential risks to the long-term reliability of the unit are significant, the unit's self-commitment may result in short-term revenue deficiencies; however, it also lowers the risk of ratepayer exposure to rising O&M expenses and preserves the unit's long-term availability for future economic dispatch.

Self-Commitment for Economic Purposes

Utilities may self-commit their coal units for economic purposes based on their own internal analysis of market conditions if a net economic benefit can be achieved by operating the coal units. Absent self-commitment, the units may remain offline due to the current limitations of SPP's market model in clearing coal units through the unit commitment process. As discussed earlier, the market model is not fully equipped to evaluate unit commitment over a multi-day period. SPP's model optimizes unit commitment with in the day-ahead market window, which is ineffective for coal-fired units that have long lead times and higher start-up costs. Market participants are responsible for evaluating unit commitment over a longer period to determine whether revenue deficiencies will persists outside of the unit commitment window and whether the unit would be available for dispatch when revenue supported the plant's operations. Additionally, a coal unit that is economically dispatched by the market will continue to remain online until the unit exceeds its minimum run time, even-though the unit was only economically evaluated within the day-ahead market window. The unit may be uneconomical in future periods but will remain online to fulfill the minimum-run time requirements.

By committing units in this fashion, the market model fails to assess whether a revenue surplus or shortfall is projected to persist for a prolonged period, which has the potential to harm customers. The market participant therefore has to evaluate whether the cumulative shortfalls would exceed the total expected foregone margins, the costs to restart the unit, and the increased risk of component failure resulting in significant maintenance expenses arising from the cycling of the unit. The utility also should consider foregone revenue and the opportunity cost of missing incremental sales during the unit's minimum down time. Incremental margins help to recover the fixed operating expenses that are passed on to utility ratepayers absent the unit's production. For baseload facilities, market participants can circumvent the SPP market commitment process by self-committing its baseload facilities. Market participants rely on forecasting methodologies for wind, weather, and load to evaluate market pricing over a unit's commitment period. Absent the self-commitment, a coal-fired generating unit would not be cleared in the DA market and remain unavailable for dispatch in the near-term when market prices are more conducive to operating the plant. If a market participant's multi-day evaluation produces a net contribution margin, the market participant should self-commit the unit.

Self-Commitment for Testing Purposes

Utilities may self-commit their coal units for testing purposes to comply with the environmental standards set by various regulatory bodies or following the installation or maintenance of certain plant components after planned or forced outages. With regard to compliance testing, utilities may have no other alternative but to self-commit a unit to make sure the unit is online and available to complete the testing requirements. Emission and air quality standards are set by various regulatory agencies and must be conducted according to the regulatory guidelines. Emissions from coal-fired generating units can vary based on the operational output of the unit. Testing requirements have become a normal operating cost for coal-fired generation. In addition to compliance testing, a utility may self-commit a unit to test its operating performance or maintenance on a replaced or repaired component performed by specialized contractors following scheduled or planned outages. Utilities often use specialized contractors to perform scheduled maintenance at predefined intervals and repair or replace components that require specialized engineering experience tools or equipment to perform the required maintenance. In the case of turbine overhauls, turbine testing is typically performed while the contractors are on-site, since the contractors have specialized tools and equipment needed to check turbine vibration at running speed and with load on the turbine. By vetting repairs while the contractor is on-site, a utility eliminates the risk that the contractor and/or equipment may be unavailable for further testing, which would lead to higher outage related costs. This testing further reduces the risk of unreliable operation of the unit when the unit is economically cleared in the DA market. The results of the DA market are financially binding on the market participant and any deviation in unit output could negatively impact the utilities ratepayers.

Staff Analysis of Self-Commitment Factors

As discussed above, a variety of factors can influence the self-commitment practices of market participants in the SPP IM. Based on Staff's review of utilities' responses, self-commitment serves as a tool utilities use to evaluate factors outside of the market-clearing engine and market model. KCP&L and the other Kansas utilities have been responsive to Staff's questions to provide a full review of its self-commitment practice and the factors operators examine when electing a commitment status for a generator. KCP&L has demonstrated that it has actively evaluated its commitment decisions to respond to changes in wholesale market pricing. The MMU whitepaper details the limitations of the market model in evaluating unit commitment for assets that have long-lead time and high start-up costs. Due to the limitations in the market model, self-commitment will continue to be used as a tool in certain situations. Staff supports the exploration of multi-day unit commitment logic to determine if changes to the market model can further reduce the incidences self-commitment and give utility operators an expanded toolset to pursue market commitment of resources. The ultimate goal in evaluating unit commitment is to manage the unit's margin opportunities to support the fixed cost recovery of the unit while limiting the unit's exposure to revenue deficiencies that hinder fixed cost recovery. More frequent cycling, when employed effectively, preserves a coal unit's operating margin by avoiding the uneconomic operation of the unit in periods of low demand. KCP&L's increased cycling efforts have the potential to benefit retail ratepayers, but ratepayers can also benefit from the self-commitment of coal units by maximizing the unit's margin opportunities and/or minimizes the risk to the long-term reliable operation of the unit.

This section detailed the market function of self-commitment and discussed the various uses of self-commitment by Kansas utilities. Understanding the decision-making processes and economic evaluations conducted by utility operators provides insight to the key drivers that influence the use of self-commitment of coal-fired generating units by market participants in the SPP IM. The next section explores the effects that self-committed generation has on the market supply curve and the economic dispatch of system resources. Staff examines the negative market forces that result from the current level of self-committed generation in the SPP IM, including the suppression of the wholesale price of energy, the alteration of economic dispatch, the distortion of pricing and investment signals, and the increased frequency of negative pricing intervals. Finally, Staff examines how the market structure of RTO/ISOs influences the compensation mechanisms provided to generators for the energy, operating reserves, and capacity.

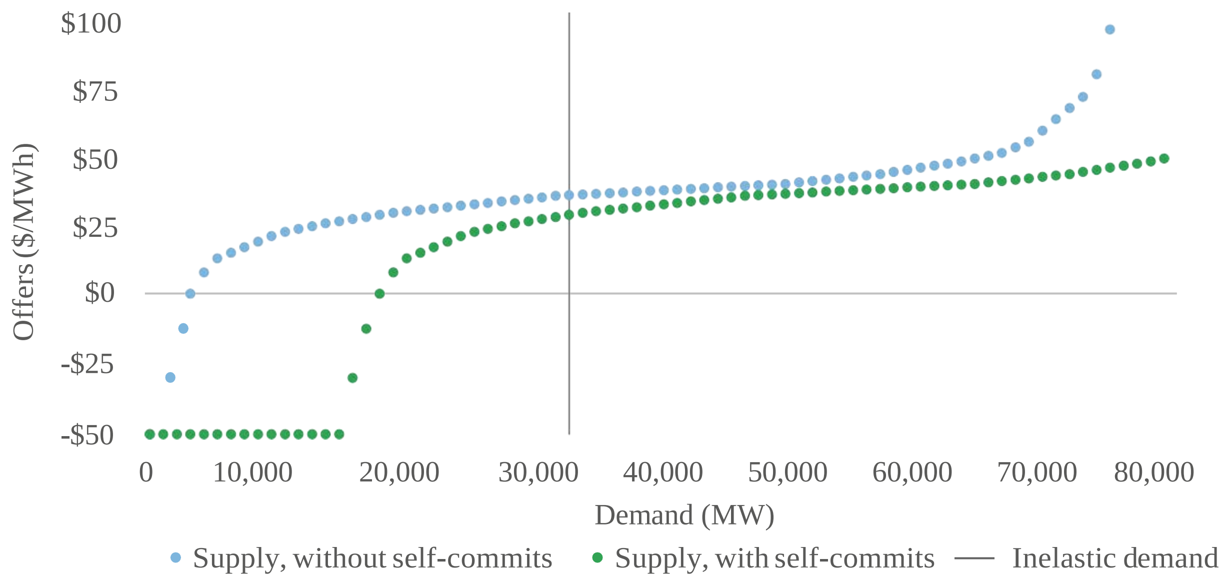
III. Effects of Self-Commitment in Energy Markets

The MMU Whitepaper provides a technical overview of unit commitment and dispatch of self-committed resources. The Whitepaper example helps to illustrate the effects self-committed resources have on the market-clearing process.[28] Functionally, self-committed resources alter the generators selected to fulfill energy demand resulting in modifications to the resource supply curve.[29] Self-committed and self-scheduled resources are omitted from the unit commitment

[28] *See* SPP MMU Whitepaper, pages 4 - 7.
[29] *See Id*, page 5.

optimization that clears the least-cost resources capable of serving regional energy demand.[30] The market model treats self-committed resources as price insensitive up to the unit's minimum economic operating parameters contained in the resource offer.[31] By treating the offer as price-insensitive, self-committed units are placed at the bottom of the supply curve resulting in a shift of the supply curve to the right.[32] Absent other variables, the rightward shift in the supply curve will reduce the market's marginal clearing price.[33] In addition to shifting the supply curve, self-committed generation changes the slope of the supply curve due to the reordering of units deployed by the economic dispatch optimization to serve regional energy demand.[34] An illustration of the effects self-commitment has on the market supply curve is detailed in the graph below.[35]

Rightward Shift in Market Supply Curve[36]



A general critique of self-commitment is that the practice depresses the wholesale price of energy, which affects the revenue stream of all resources that are online producing energy. Along with the effects of market price suppression, the economic-minimums of self-committed resources can create a resource-specific dispatch floor in the market.[37] The economic dispatch algorithm interprets the self-committed unit as a constraint that it must solve in order to optimize economic dispatch across the footprint.[38] The economic dispatch engine prioritizes self-committed units as "must-run" during the optimization process, and the self-committed units cannot be taken off-line by the dispatch engine for economic purposes.[39] During periods of low energy demand, the

[30] *See Id.*
[31] *See Id*, page 6.
[32] *See Id.*
[33] *See Id*, pages 6 - 7.
[34] *See Id*, page 7.
[35] *See Id*, page 6.
[36] The blue supply curve represents supply without self-committed megawatts, whereas the green supply curve represents supply including self-committed megawatts.
[37] *See Id*, page 7.
[38] *See Id.*
[39] *See Id.*

economic dispatch engine will prioritize curtailing market-committed generation ahead of self-committed generation with self-committed units holding the lowest priority for curtailment.[40]

Short-term and Long-term Market Effects

While self-committed generation introduces a number of short-term market inefficiencies, self-commitment can fundamentally alter the market feedback mechanism, which poses the greatest risk to the long-term operation of the market. As discussed earlier, self-committed resources alter the unit commitment and economic dispatch optimizations that are designed to drive market efficiencies and minimize regional production costs. In periods of low demand, self-committed units will likely experience intervals where the wholesale price of power is less than the short-term variable cost to produce the energy. The margins produced in on-peak hours must first cover the revenue deficiencies in off-peak hours or through seasonal periods of low energy demand prior to contributing to the fixed cost recovery. Utilities can effectively manage the impact of revenue deficiencies by cycling the unit when possible or allowing the unit to remain offline avoiding prolonged periods of revenue deficiencies. From a renewable generator's perspective, self-committed units drive down the marginal clearing price of energy and can displace lower cost resources from being dispatched by the market. Additionally, self-committed units are allowed to continue producing energy in periods of low energy demand while lower cost renewable resources are curtailed. For a renewable generator, the self-commitment practices of integrated utilities could materially affect the success or failure of the project.

Market participants and generation investors rely on the market's feedback mechanisms for short-term and long-term decision-making. When distortion occurs in the market feedback loop, the distorted feedback can drive a series of inefficient market outcomes. Based on the distorted market signals, a market participant may pursue sub-optimal strategies to maximize its profits. While certain strategies may result in short-run economic benefits for a market participant, the strategies employed by the market participant may come at the expense of other regional competitors or result in a poor economic outcome for the market as a whole. In turn, other regional competitors may employ similar market strategies that further distorts pricing and investment signals.

Due to the length of time needed to construct generation assets, market participants or merchant developers often rely on forward pricing and energy demand forecasting to evaluate investment in future generating projects. The goal of the evaluation is to determine whether the revenue generated from energy sales will support the cost to finance, construct, operate, and eventually retire the unit. When these long-term investment decisions are based on distorted market data, the long-term efficiency of the market is likely to be negatively impacted. When investment signals are highly distorted, investment in uneconomic projects could result in stranded costs or asset bankruptcy, and development of economic projects may not be undertaken due to market uncertainty or increased investment risk.

As new resources are brought online, the competitive balance of existing resources adapts to a new competitive equilibrium. As more renewable generating units compete for limited demand in an over-supplied market, the new entrants may apply further downward pressure on the market-clearing price and increase the frequency of negative pricing. Retirement decisions for generation units are often predicated on the obsolesce of the generating asset when compared to replacing the

[40] *See Id.*

existing generation asset with a more efficient generating resource. An economic benefit calculation is usually performed, demonstrating the resource is the low cost asset and results in cost savings to retail ratepayers. If the underlying pricing signals are inaccurate or highly distorted, market participants may invest in non-profitable assets resulting in stranded investment in assets. For a renewable generation developer, the revenue stream may be insufficient to recover the operating unit leading to an asset sale or bankruptcy. For integrated utilities, inopportune investment can result in cost of service increases to serve retail ratepayers. Utility assets are capital intensive and require long operating lives to recover the fixed cost of the asset. Therefore, minimizing the distortion of pricing and investment signals lowers the risk of long-term market inefficiencies arising.

Negative Pricing Intervals

When self-committed generation accounts for a significant percentage of market supply and periods of low energy demand occur, the market-clearing price can experience low or negative pricing intervals. Negative pricing intervals occur in periods of low energy demand, due to the inflexibility of the resources in the wholesale market and the ability of renewable resources to absorb negative energy prices for each unit of output and still make a profit. Therefore, the market is incentivizing purchasers to take the excess supply surplus. Mechanically, non-wind units are dispatched to their operating minimums allowing wind resources to set the price.[41] When formulating the offer-curve for wind units, market participants will often reflect the impact of production tax credits in the supply curve, which accounts for negative clearing price. While the production tax credits incent renewable resources to generate, the negative pricing intervals reflect an over-supplied generation market competing for limited demand in off-peak hours. The generation mix within the RTO will influence the frequency of negative pricing intervals as self-committed baseload resources (coal, nuclear, hydro) compete with renewable generation with zero fuel cost. From a market perspective, negative intervals send a price signal to impacted generating units to incent the flexible operation of the unit and alter its future unit commitment decisions. If negative pricing intervals increase in frequency, the fixed cost recovery of self-committed resources may be materially impacted. Market participants with self-committed resources are incentivized to explore alternative unit commitment strategies or revise operating parameters that act as system constraints when the market is over-supplied.

Negative pricing intervals occur in both the DA and RTBM, but negative pricing is more frequent in the RTBM. From 2017 – 2019, the DA market experienced negative pricing intervals in approximately 1% to 3% of all market hours while the RTBM market experienced negative pricing in 3.5% to 7% of all market intervals.[42] Negative pricing intervals are more frequent in the RTBM due to two primary factors. First, the RTBM settles in five-minute intervals, which results in greater volatility when compared to the DA Market. Second, the RTBM has a significant level of unaccounted for generation that becomes available in real-time. Unaccounted generation consists of four primary categories: market imports; reliability unit commitments; incremental self-committed generation; and under-scheduled wind resources in the DA market. In the RTBM, unaccounted for generation alters the supply curve by shifting it outward and causes real-time

[41] The market honors the minimum operating limits for all self-committed generation resources and cannot take the units off-line for economic purposes.

[42] *See* SPP Annual State of the Market for 2019, Section 4.14: Negative Prices, Figure 4-18 and Figure 4-19, pages 150 - 151.

prices to drop relative to the DA market.[43] In 2019, under-scheduled wind units accounted for roughly 58% of the 2,300 megawatt-hours of incremental energy available in real-time.[44] Wind resources remain under-represented in the DA market. In 2019, the MMU notes that 84% of wind generation was cleared in the DA market, down one percent from 2018.[45] Incentivizing the participation of wind resources in the DA market has the potential to both lessen price deviations between the DA and RTBM and reduce the incidences of negative pricing in the RTBM.

Self-Commitment Benefits in Managing Retail Coal Assets

Self-commitment, when used effectively, can benefit both retail ratepayers and the SPP IM market as a whole. As previously discussed, the unit commitment optimization examines costs within a pre-defined market optimization window. The unit commitment algorithm does not have the capability to examine a unit's expected revenue and production costs beyond the operating window. If a coal unit fails to clear the unit commitment process, the unit may remain unavailable in subsequent periods due to the unit's minimum downtime. Long-lead times and higher start-up costs of coal units act as additional constraints in clearing the unit commitment process. Due to the limitations in the market model, market participants often perform their own economic analysis over an extended period to determine if market revenue supports operating the unit. When self-committing a resource, a market participant accepts the risk that market-clearing price may not allow the full-cost recovery of an asset during the commitment period and the unit will not be eligible for make-whole payments. Absent self-commitment, the coal unit is likely to remain off-line and may only clear the market in high demand seasons. If the plant remains offline, the market participant may risk lost margin opportunities that act as a real-opportunity cost, which the market participant should consider in performing its own economic analysis and risk assessment.

When a utility elects to self-commit its resources, the market participant is likely to perform a contribution margin analysis by examining the expected revenue of the unit compared to the production cost of the unit over the expected commitment period. If the variable costs of production exceed unit revenue, self-commitment of the asset would result in an operating loss and the unit should not be committed. If a net contribution margin is likely, a utility may examine its past offers to determine whether the unit is likely to clear the unit commitment process if market committed. If the unit produces a net contribution margin and the resource is unlikely to clear the SPP unit commitment process, an integrated utility's best course of action is to self-commit the resource to maximize the long-term value of the asset for retail ratepayers. When performing this evaluation, the market participant's economic analysis relies upon the operational history of the asset, while incorporating projections for wind, weather, and system demand. Tracking the success or failure of the unit commitment strategies is important to improve forecasting techniques and improves the decision-making processes for future unit commitment. Utility operators have a wealth of market information to analyze past commitment strategies and track the economic outcome of its commitment strategies.

Market Structure and Integrated Ownership

Integrated ownership of utility assets complicates the calculation of a net benefit to retail ratepayers from low wholesale energy prices in comparison to a deregulated energy market. The underlying

[43] *See Id*, pages 147 - 148.
[44] *See Id*, page 148.
[45] *See Id*, page 147.

structure of deregulated energy markets splits the generation of wholesale energy supply from the retail suppliers that purchase power to serve load. In a deregulated market, the generation asset must produce enough revenue from the sales of energy, operating reserves and capacity to cover the fuel costs, the variable and fixed operating costs, maintenance expenses, and the cost of capital investment. If a generating unit's revenue fails to recover these costs, the generating unit would not be profitable. In a deregulated market, an unprofitable unit would likely be moved towards retirement, barring any reliability issues. The success or failure of the unit ties directly to the underlying economics of the energy and capacity markets. In deregulated markets, retail suppliers are indifferent to the source of generation; and therefore, the supplier's primary goal is to achieve the lowest purchase power expense to retain its customers. If consumers can achieve a lower cost of power from a power marketer, the consumer is free to choose an alternative provider.

In vertically integrated markets, like SPP, integrated utilities and their ratepayers are both generation owners that sell energy into the market and purchasers of energy to serve retail load. The market-clearing price applies equally to the sale of energy from generating assets and acquisition of energy to serve load. If generation output and load purchases were matched identically over a production period, the net impact of the marginal energy price would net to zero, leaving retail ratepayers to cover the production costs of the underlying asset.[46] This scenario would mirror the cost recovery methodology under the SPP EIS market. In the SPP IM, integrated utilities can take advantage of market pricing by altering unit commitment strategies. If a unit's productions costs exceed the marginal clearing price, integrated utilities may provide consumers benefit by purchasing energy from other resources rather than incurring excess production costs to run the utility's assets. The market price of energy provides a relevant data point to examine the variable production costs of self-committed resources to determine if ratepayers either benefit or are harmed by a utilities' self-commitment practices. While the vast majority of production costs included in the ECA are variable expenses, the costs from long-term fuel contracts, fuel handling expenses, rail transportation expenses, and train car leases act as fixed production costs in the near-term. These costs will continue to be incurred by the utility while a coal unit is offline. Ultimately, the integrated ownership of utility assets requires a broader approach in examining the impact of utilities' self-commitment strategies on retail ratepayers.

Compensation for Generation Capacity

In most RTO/ISO markets, market participants are compensated directly for the generation capacity the resource provides to meet future system demand and maintain the reliability of the system. Compensating generation capacity incents market participants to serve future retail load and invest in generation assets necessary to meet future energy demand. In most RTO and ISOs, generation owners are provided compensation for generating capacity through separately administered capacity market auctions. SPP and Electric Reliability Council of Texas (ERCOT) are the only RTO/ISO markets that do not operate capacity markets. ERCOT's market is deregulated and operates an energy and operating reserve DA and RT market. While ERCOT does not operate a capacity market, ERCOT relies on market mechanisms like its Operating Reserve Demand Curve and scarcity pricing mechanism that includes a System Wide Offer Cap (SWOC)

[46] Staff's simplified example only includes energy charges and would not include transmission congestion rights, congestion charges, line losses, or other SPP IM activity.

of $9,000 per MWh, which incentivizes the investment in future generation capacity.[47] The scarcity pricing mechanisms allows generators to recover up to $9,000 per MWh, which was hit multiple times in the RTBM during peak summer demand in August of 2019. Market participants in ERCOT rely primarily on natural gas generation to serve customer load with a generation mix comprised of 47% natural gas, 20% coal, 20% wind, 11% nuclear and 2% other.[48] The high-mix of natural gas with wind resources can result in high energy prices in peak demand seasons or when wind is unavailable, which allows resources a better opportunity to recover the fixed costs of the assets. Additionally, baseload resources contribute to a smaller percentage of the market allowing natural gas resources to cycle in periods of low demand. In 2019, ERCOT day-ahead around-the-clock pricing averaged $38 per MWh.

In contrast, integrated utilities in SPP must meet a planning reserve margin and invest in generation capacity necessary to meet its future energy demand and capacity obligations.[49] SPP's planning reserve margin has remained at 12% for load serving entities since 2016. Unlike other RTO/ISOs, integrated utilities in SPP are required to self-fund their own capacity with state regulatory commissions providing oversight for generation investment.[50] SPP does not operate a capacity market or have any market mechanisms to compensate utilities for the self-funded capacity. Fundamentally, integrated utilities in SPP must recover the full cost of ownership for its generating assets from energy and operating reserve sales or pass-on the unrecovered cost to retail ratepayers through utility rate cases. Unlike ERCOT, SPP's generation mix is more diverse with energy generated from 34.8% coal, 27.4% wind, 25.9% natural gas, 6% nuclear, and 5.6% hydro.[51] The mix of inflexible baseload resources (coal, nuclear, hydro) and exponential growth of wind resources has contributed to low wholesale energy prices and increases in the frequency of negative pricing intervals. SPP's day-ahead market price averaged $22.04 in 2019.[52] The growth of renewable generation in the footprint has resulted in a significant amount of excess generation capacity in the SPP market. According to the 2020 SPP Resource Adequacy Report, load serving entities have approximately 4,000 MW of capacity in excess of the planning reserve margin and generation-only owners contribute another 600 MW of excess capacity in 2020.[53]

SPP's requirement for utilities to self-fund their own capacity further complicates a net ratepayer benefit/harm calculation due to the lack of compensation for capacity. While there is currently enough capacity to serve participants in SPP through 2025, integrated utilities with uneconomic coal units may begin retiring the assets due to the inability to generate enough revenue to cover

[47] *See* ERCOT State of the Market Report for 2019, Appendix, Section I: Review of Real-time Market Outcomes, page A-7; https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf.
[48] ERCOT State of the Grid Report for 2019, page 8; http://www.ercot.com/content/wcm/lists/197391/2019_ERCOT_State_of_the_Grid_Report.pdf.
[49] The SPP IM has a provision for scarcity pricing to ensure adequate reserves for dispatch of regulation and operating reserve products; however, the scarcity pricing provision in SPP is not meant to drive investment in capacity. In SPP, regulation demand curves, both up and down are capped at $600/MW. Operating reserve demand curves include a price cap of $1,100/MW.
[50] Load Responsible Entities must maintain a planning reserve margin of 12%. Reserve Margin is the amount of Deliverable or Prospective Resources minus the Net Internal Demand.
[51] *See* SPP's Fast Fact webpage accessed on September 3, 2020; https://spp.org/about-us/fast-facts/.
[52] *See* SPP Annual State of the Market Report for 2019, Section 4: Market Prices and Costs, page 131.
[53] *See* 2020 SPP Resource Adequacy Report, page 4; https://spp.org/documents/62405/2020%20spp%20june%20resource%20adequacy%20report.pdf.

the full cost of the asset. Rapid retirement of baseload resources would likely need to be studied further to analyze whether reliability issues arise as baseload coal units exit the system.

IV. MMU Study of Self-commitment in the SPP IM

The MMU Whitepaper includes a section of empirical study of market participants' offer behavior from March of 2014 through August of 2019. The empirical analysis contains data on the current use of self-commitment and examines the trends in unit commitment decisions over the study period. In addition, to the empirical analysis, the MMU conducted a series of simulations that resettled the market for two self-commitment scenarios to examine the impact self-committed generation has on market-clearing prices and regional production costs. In this section, Staff will highlight areas of concern raised by the MMU when examining the market effects of self-committed generation. Additionally, Staff discusses the methodology used by the MMU to resettle the market, the scenarios studied, and the market impact of each scenario. Finally, Staff presents the MMU's findings when examining the various scenarios studied.

State of the Market Reports

The State of the Market Reports provide SPP's stakeholders with an annual snapshot of market activity and serves as a repository of market data. These reports provide trend analysis that is helpful in understanding how market practices evolve overtime and provides year-to-year comparative data on key areas in the SPP IM. The SPP State of the Market Reports provide an overview of market participants' unit commitment analysis and offer behavior, which laid much of the groundwork included in the empirical analysis section of the MMU Whitepaper. The MMU compiles the Annual State of the Market Reports from its monthly analysis included in presentations provided to the SPP Market Working Group (MWG). The MMU has long raised its concerns on the level of self-commitment in the SPP IM and actively advocated for market participants to reduce the incidences of self-commitment when possible.

MMU Empirical Analysis on Self-commitment and Negative Pricing

For 2019, the breakdown of the average total offered capacity by commitment status includes the following: 55% market-commitment, 25% self-commitment, 16% outage, 2% reliability and 3% not participating.[54] When the IS Members integrated in 2015, the breakdown in average percentage of offered capacity included 46% market-commitment and 39% self-commitment.[55] Over the past five years, the average offered capacity for resources in SPP has gradually shifted with more market participants electing to market-commit resources. From the MMU's perspective, the declining trend of resources electing to self-commit is a positive market outcome, but the MMU points out that self-commitment still accounts for 25% of the average offered capacity. While self-commitment still accounts for a significant percentage of average offered capacity, self-committed resources only account for 8% of initial starts, which highlights market participant's desire to keep self-committed units online after the initial start even during low demand periods.[56] The market participant trend to keep the unit online likely reflects the unit's high start-up costs and impacts to the plant availability due to minimum down time requirements of the unit.

[54] *See* SPP Annual State of the Market Report for 2019, page 91.
[55] *See* SPP Annual State of the Market Report for 2016, page 5.
[56] *See* SPP Annual State of the Market Report for 2019, page 91.

The MMU Whitepaper includes a breakdown of the dispatch volume between market and self-committed resources. When examining the percentage of day-ahead economic dispatch megawatts by commitment type, the volume of dispatched self-committed megawatts is declining over the study period. In 2015, self-committed units accounted for roughly 70% of the total dispatch megawatts, which was the peak in self-committed volume.[57] By 2017, self-committed units accounted for a little under 60% of the production volume of all dispatched megawatts.[58] In 2019, self-committed units still represent nearly half of all the energy produced in the market.[59] The MMU further points out that the downward trend in dispatch volume of self-committed resources represents improvement; however, roughly half of all dispatch volume in the SPP IM was produced from a resource that was not economically selected through the merit-based unit commitment process in 2019.[60]

In its Annual State of the Market Report for 2019, the MMU 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. …In order to improve market commitment in the SPP market, the MMU recommends that SPP and stakeholders look to find ways to reduce the incidence of self-commitment and to consider adding an additional day [to] the day-ahead unit commitment process.[61]

In its State of the Market Report, the MMU addresses the current market challenges of dealing with uncertainty in the market. In 2019, SPP Operators called on fast start/ramping resources to meet ramping needs to deal with market uncertainty resulting in make-whole payments of $101 million, up nearly 40% year-over-year.[62] Wind resources continue to be under-represented in the DA market, which lowers real-time pricing and drives pricing deviations between the DA and RTBM.[63] Systematic under-scheduling of wind resources in the DA market can contribute to distorted price signals, suppressing of real-time prices and affecting revenue adequacy for all resources.[64] The mix of wind resources and inflexible generation contribute to the increase frequency of negative pricing intervals, which more than tripled in the DA market and doubled in the RTBM year-over-year in 2019.[65] In order to more effectively deal with market uncertainty, SPP is proposing the implementation of an uncertainty product that will work similarly to and in conjunction with the recently FERC-approved ramping capability product.[66] The two products should severely limit the need for the use of committing the uncompensated or instantaneous load capacity. With the prolific growth of wind generation in the SPP market, the SPP supply surplus represents a unique challenge to the current market design. The influx of cheap renewables

[57] *See* MMU Whitepaper, Figure 4.1: Percentage of Megawatts Dispatched by Commitment Status, page 16.
[58] *See Id.*
[59] *See Id.*
[60] *See Id.*
[61] SPP Annual State of the Market Report for 2019, page 7.
[62] *See Id*, page 165.
[63] *See Id*, pages 288 - 289.
[64] *See Id*, page 289.
[65] *See Id*, Figures 4-18: Negative Price Interval in DA Market and Figure 4-19: Negative Price Intervals in Real-time Market, pages 150 - 151.
[66] FERC approved SPP's Ramp Capability Products in its Order Accepting Tariff Revisions on July16, 2020 in Docket No. ER20-1617-000. The Ramping Capability Products plan to be implemented in the second quarter of 2021.

competing with inflexible baseload resources contributes to the incidences of negative pricing in the market. Looking forward, the renewable energy resources in the SPP queue will likely contribute to an over-supplied market during periods of low demand. With these trends, the MMU recommends stakeholders evaluate market enhancements to help lower the incidents of self-commitment and incentivize participation of wind resources in the day-ahead market. As more renewable resources in the SPP queue are brought online, the market surplus of resources will continue to apply downward pressure on the price of wholesale energy and increase the risk of resource curtailment to current and future wind projects.

In its Annual State of the Market Report for 2018, the MMU stated,

> …[T]he MMU remains concerned about the frequency of negative price intervals. Negative prices may not be a problem in and of themselves; however, they do indicate an increase in surplus energy on the system. This may be exacerbated by the practice of self-committing of resources and manual commitments for capacity. In the SPP market where there is an abundance of capacity and significant levels of renewable resources, negative prices can occur when renewable resources need to be backed down in order for traditional resources to meet their committed generation. Moreover, unit commitment differences, due to wind resources not forecasting the full amount in the day-ahead market and then producing more in the real-time market, can create differences in the frequency of negative price intervals between the day-ahead and real-time markets. This disparity between the markets negatively impacts the efficient commitment of resources.
>
> As more wind generation is anticipated to be added over the next several years, the frequency of negative prices has the potential to increase. Negative price intervals in the day-ahead highlight the need for changes in market rules to address self-committing of resources in the day-ahead market and the systematic absence of some variable energy resources' forecasted outputs in the day-ahead market to improve market efficiency.[67]

<u>MMU Analysis of Self-Commitment on Price Formation</u>

The MMU studied the effects of self-commitment on price formation over the study period. To analyze the effects of self-commitment on price and price formation, the MMU evaluated the frequency and magnitude of self-commitment in addition to the time self-committed generators set the market price. Over the study period, at least one self-committed unit was marginal in roughly 75% of the DA market hours.[68] The MMU explains that self-committed units can set the market-clearing price if the resources produces the marginal unit of supply when dispatched above the economic minimum.[69] If the self-committed unit had elected a market-status, the unit commitment optimization may not have cleared the self-committed unit; and consequently the self-committed unit may not have supplied the marginal unit of energy.[70] The MMU's example highlights the impact that a self-committed unit can have on price formation in the market.

[67] *See* SPP Annual State of the Market Report for 2018, pages 125 - 126.
[68] *See* MMU Whitepaper, page 27. The MMU's calculation is based on a self-committed unit setting the marginal energy price within the DA hour. The MMU further notes that more than one resource can produce the marginal unit of output within the same market hour.
[69] *See Id*, page 28.
[70] *See Id.*

In the study, the MMU further examined the frequency that self-committed or market-committed unit set the marginal energy price.[71] The MMU found that market-committed units set the marginal energy price in roughly two-thirds of the day-ahead market intervals and self-committed units set the marginal energy prices in one-third of the day-ahead market intervals.[72] When a self-committed unit was the marginal resource, coal-fired units accounted for the vast majority of time on margin when compared to other fuel types.[73] During the study period, the MMU found that the average day-ahead market prices were systematically lower when at least one self-committed unit provided the marginal unit of output.[74]

Self-commitment Impact on Congestion Costs and Hedging Products

The self-commitment of coal units affects both congestion costs and TCR revenue. The MMU empirical analysis of congestion costs found that generators are impacted differently based on the unit's fuel type and commitment status.[75] Coal, wind, and hydro all had dramatically lower LMP prices due to congestion costs while natural gas resources tend to see increases in the LMP due to congestion[76]. The MMU points out that the congestion profile is more balanced for market-committed units with some units earning more than the system marginal price and others units earning less than the marginal price.[77] However, self-committed units will predominantly earn less than the system marginal price due to congestion charges.[78]

As discussed previously, both generation and load are charged congestion costs in the market; however, generation is charged congestion cost through reductions in the LMP while load is charged congestion through increases in the LMP. In the State of the Market Report released for Spring 2019, the MMU conducted a three-year study of congestion costs[79] from 2016 – 2018.[80] In its study, the MMU found that congestion costs associated with generation (injection activities) materially exceeded the congestion cost for load (withdrawal activities).[81] Physical generation accounted for the vast majority of congestion costs over other injection-related activities.[82] Self-committed generation accounted for nearly 75% of the total congestion costs related to physical generation with market and reliability commitments accounting for 25% of congestion costs.[83] The MMU noted that by self-committing their resources, market participants are choosing to incur

[71] Unlike the prior calculation of the number of hours on margin, the MMU's examination measured the frequency a self-committed or market-committed unit set the marginal energy price.
[72] *See* MMU Whitepaper, page 29.
[73] *See Id,* Figure 5-2: Percentage of Marginal Hours by Fuel Type, page 29.
[74] *See Id,* page 30.
[75] *See Id,* Figure 5-5: Congestion Dollars by Fuel Type and Commitment Status, page 32.
[76] See *Id.*
[77] See *Id.*
[78] See *Id.*
[79] The MMU only included market participants that received the ARR closeout in the study. Figures presented throughout section only included those participants who received the ARR closeout. Market participants who receive the ARR closeout have ARR nomination caps, which source from transmission service reservations.
[80] *See* SPP State of the Market Report – Spring 2019, Section 6: Special Issues, page 53 - 62; https://www.spp.org/documents/60307/spp_mmu_qsom_spring_2019.pdf.
[81] S*ee Id,* Figure 6-3: Sources of Congestion by Market Action, page 56. Injection related activities include the following: Generation, Import transactions, Bilateral Settlement Scheduled Generation, and Virtual Generation. Withdrawal-related activities include the following: Load, Export Transactions, Bilateral Settlement Scheduled Load, and Virtual Load.
[82] *See Id,* Figure 6-6: Sources of Injection Congestion Classified by Market Action, page 58.
[83] *See Id,* Figure 6-7: Generation Congestion: Market and Reliability vs Self-Commitment, page 59.

congestion costs in spite of the associated congestion exposure.[84] A key takeaway from the MMU's study is that each market participant's portfolio of market actions differ from other participants, and in some instances, the participants' actions differ quite materially.

The impact of self-commitment is not limited to congestion costs; it extends to the revenue generated from a market participant's portfolio of congestion hedging products. The MMU conducted an analysis of the profit and losses resulting from hedging settlements netted against the day-ahead congestion for the subgroup of participants.[85] While year-to-year results varied, participants experienced fluctuations in the magnitude and, in some cases, the direction of profitability.[86] A few of the market participants' profitability outcomes were significant.[87] In studying the revenue and expenses related to congestion, the MMU found the more advantageous a participant's congestion position, the more likely a participant was to experience profits, and conversely, the more disadvantageous the congestion position the more likely a participant was to experience losses.[88] More specifically, for the subgroup of participants, the correlation between profits and congestions was five times larger than the correlation between profits and revenues.[89] Therefore, the MMU concludes market participant's profits were influenced more by congestion costs than by congestion hedging revenues.[90]

When congestion charges reduce a generator's revenue, the congestion charges are supposed to act as a pricing signal to the market participant to incentivize the operator to modify its market behavior in the short-term and provide a signal to other generation investors not to build generation in the long-term. If the market behavior is not modified, transmission owners are incented to build transmission infrastructure to reduce the cost of congestion. As demonstrated by the MMU's study, the self-commitment decisions made by market participants can alter price formation and distort the pricing signals. Absent alternative market strategies, self-commitment can lead to market inefficiencies and the build out of unnecessary transmission infrastructure. While self-commitment can increase congestion costs, market participants' TCR portfolios will provide additional TCR revenue for hedged transmission pathways that may offset all or some of the increase in congestion costs. The MMU's study concludes that a market participant's profits and losses can vary between market participants and rate years; however, the market participant's profitability has been influenced more by congestion costs than by the revenue generated from a market participant's congestion hedging portfolio.

MMU Approach to Managing Price Signal Distortion

The competitive forces in a free market tend to act as a disciplining agent that influences market behavior and limits the risks market participants are willing to undertake. Market participants will be incented to pursue efficient long-term market strategies for the economic benefit of its resources. Pursuing inefficient market strategies will result in uneconomic outcomes for the generating resource, resulting in revenue deficiencies, asset bankruptcy, or stranded retail assets. Competitive markets tend to be efficient over the long-run, so short-term market inefficiencies can

[84] *See Id*, page 59.
[85] *See Id*, page 53.
[86] *See Id*, Figure 6-1: Congestion Hedging Settlements Net of Day-Ahead Congestion, page 54.
[87] *See Id*, page 54.
[88] *See Id*, Figure 6-2: Revenue, Cost and Profitability Rankings by Market Participant, page 59.
[89] *See Id*, page 59.
[90] *See Id*, page 62.

arise as new, more efficient assets enter the market or changes in the relative price fuel impact the competitive equilibrium in the market. As wholesale energy prices in SPP declined, market participants adapted their market strategies to reduce the self-commitment of coal units, which illustrates how economic outcomes influence the market behavior of participants.

The SPP MMU and the MISO Independent Market Monitor (MISO-IMM) have taken vastly different approaches to addressing the self-commitment of coal resources in wholesale energy markets. Both wholesale markets have a significant level of self-committed generation from baseload coal units and substantial renewable wind resource development in their regional footprint. The SPP MMU has approached self-commitment more proactively, urging market participants to reduce self-commitment when possible and advocating for market enhancements that can lower or mange resource uncertainty, incentivize participation in DA market, and reduce unit commitment limitations within the existing market model. In contrast, the MISO-IMM approach has been more passive, allowing market forces to discipline market participants to pursue long-term economic outcomes while looking for abuses of market power in bidding and offering strategies. The MISO market design and cost recovery may influence the need for a less proactive approach to self-commitment. The MISO market employs a broader definition of short-run marginal costs allowing market participants to recover major maintenance expense and operates a capacity market providing compensation for resource capacity.

From an economic perspective, the self-commitment of coal resources puts downward pressure on marginal energy prices, distorts pricing signals, and gives rise to resource uncertainty. These effects influence the investment signals that drive market behavior and give rise to market inefficiencies. The SPP MMU's more proactive approach in evaluating the unit commitment and providing market data and trend analysis for self-committed units aids the decision-making processes of regional stakeholders. By recommending market enhancements, the MMU generates a conversation on the limitations in the market model that influence market participants use of self-commitment. Reducing the volume of self-commitment through market education or market enhancements minimizes the long-term effects of price and investment signal distortion that give rise to market inefficiencies.

If effectively employed, the addition of a multi-day market would allow integrated utilities to rely on the market to commit and dispatch coal resources reducing the need for participants to perform their own economic analysis outside the market model. Multi-day unit commitment logic would insure the resources cleared and dispatched by the market were the least-cost resources the market could employ to serve retail demand in the footprint. While the SPP MMU has proactively advocated for parties to examine market-commitment of its resources, the MMU fully acknowledges that self-commitment performs a critical market function for market participants and has not advocated for restriction or limitations to market participant's ability to self-commitment a resource. In the MMU Whitepaper, it provides further comments on the issue:

> Self-commitment represents a significant portion of the transaction volume in the Integrated Marketplace, and while it cannot be eliminated completely, the practice can likely be reduced substantially. By reducing self-commitment, prices and investment signals will likely be less distorted. A smaller distortion will likely help market participants make better short-run and long-run decisions, which tends to coincide with improved profit maximization. Enhanced

> profit maximization combined with effective regulation and monitoring will likely lead to ratepayer benefits in the form of cost reduction.
>
> While we have seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represent about half of the generation in the SPP market. Given our results, we recommend that the SPP and its stakeholders continue to find ways to further reduce self-commitments. Many resources have switched from self-commitment to market status over the past few years, and it is possible that many more could switch without any market enhancements.[91]

Market Enhancements

The MMU has been active in evaluating and recommending market design changes that could lower the incidences of self-commitment. The MMU participates in the SPP Market Working Group (MWG) and fully supports the market enhancements recommended in the HITT Report. The MMU has acknowledged that limitation in the unit commitment software has added to the incidences of self-commitment. The MMU articulated the limitation of the current unit commitment in the Annual State of the Market Report for 2018:

> 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 the 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. This is not the optimal solution.[92]

Evaluating multi-day unit commitment logic is on the high priority list for the MWG; however, the complexity of the market design and implementing the logic into the market model means a multi-day market will not be operational in the near-term. SPP is currently in development of a multi-day forecast study to forecast hourly commitment and prices over a 4-day rolling period. SPP plans to use the results of the forecast to improve accuracy and help navigate the design of the binding multi-day market. The MWG will also be evaluating other HITT Strategic Initiatives for market enhancements for improving supply flexibility or market efficiency. HITT Initiatives targeting supply flexibility and market efficiency include SIR17 – Fast Start Resource Enhancement, SIR19 - Uncertainty Product for Capacity and Ramp, SIR30 – Energy Storage Resources Phase 2, and SIR50 - Incent Renewable Energy Offered in the DA.[93] As more renewable generation enters the market, the market enhancements will provide SPP operators and market participants with additional tools to manage self-commitment, negative pricing, and market uncertainty. With increased tools, the market can more effectively manage the current resource surplus that contributes to the short-run market inefficiencies.

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[91] *See* SPP Whitepaper, page 42.
[92] *See* SPP Annual State of the Market Report for 2018, pages 243 - 244.
[93] Staff listing of HITT Initiatives targeting supply flexibility and market efficiency is not exhaustive. Over 50 HITT Initiatives were included and prioritized by the MWG in the Road Map Initiative Ranking with over 30 Initiatives receiving a high to medium priority ranking.

<u>MMU Whitepaper: Market Simulations</u>

Along with the empirical analysis provided in the Whitepaper, the MMU ran a series of simulations to resettle the market for one week per month from September 2018 to August of 2019. The simulations were designed to study two primary assumptions: (1) all resources are market-committed, and (2) all generation offered in market status can be started economically by the day-ahead market. The key takeaways from the simulated market results include:

- When the market made unit commitment decisions and lead times remained unchanged, both market-wide production costs and market-clearing prices for energy increased.[94]
- When the market made unit commitment decisions and lead times were modified to allow the day-ahead market to commit the resources with long lead times, market-wide production costs were essentially unchanged and market-clearing prices for energy increased.[95]
    - System prices increased by about $2 per MWh or 7% on average.[96]
    - Congestion prices changed by about – $1 per MWh to $1 per MWh on average.[97]
- To optimize long-lead time resources' participation in the market, the economic commitment process would need to solve over a longer market window (e.g., over a two-day period rather than just one day).[98]

<u>Overview of Self-Commitment Simulations</u>

A full review of the self-commitment simulations can be found in Chapter 6 of the MMU Whitepaper. Below is a basic summary of the MMU's simulation methodology, scenarios explored, and key findings. Following the summary, a detailed overview of the MMU analysis is presented for each self-commitment scenario, which includes the market impact of resettlement on the marginal energy price and production costs. For its simulations, the MMU used the IM software to resettle the first week of each month over the study period. The MMU reduced the sample size to the first operating week per month due to run-time constraints. The MMU stated the sample size was significant enough to capture a wide variety of market conditions and the annual seasonality in the market.

The MMU executed three scenarios using the effective version of the actual IM software associated with each operating day to simulate the economic unit commitment and dispatch optimizations. The first scenario was primarily used to validate the MMU process and methodology by re-running the market day and comparing the results to the actual data. The validation cases were then used as the base inputs for the second and third scenario. In the second scenario, the MMU changed the offer statuses of only self-committed resources to a market-commitment status. Then, the MMU turned off any resources that were online from the prior operating day, so the market software could make all unit commitment and dispatch decisions without optimizing the generators already producing power. Finally, all units were treated as if the unit met its minimum down time from the prior operating day. Following the changes outlined, the MMU resettled the market. The third

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94 *See* MMU Study, page 1.
95 *See Id*, page 2.
96 *See Id.*
97 *See Id.*
98 *See Id.*

scenario included the changes in the second scenario; however, the MMU also reduced the generator's lead times to simulate extending the day-ahead market optimization window, and then resettled the market. The MMU s key findings from the resettlement scenarios are as follows:

- The key to reducing self-commitment while not increasing costs is multi-day economic unit commitment.[99]
- Increasing the optimization window by another 24 hours allows the market to optimize resources with long start-up times more effectively. This enhancement, combined with a reduction in self-commitment, would likely benefit ratepayers by reducing production costs in addition to sending more clear investment signals.[100]
- If the optimization window is not lengthened, and self-commitment is eliminated, investment signals would be more clear, but production costs would likely increase.[101]

<u>Scenario 1 – Validating Resettlement</u>
The main objective of Scenario 1 was to validate the legitimacy of the MMU's testing framework, which involved a mixed integer optimization program that solves for unit commitment and dispatch. Because of the software's approach to optimization, the market solutions can deviate even when using identical inputs. When simulating a market day, the MMU explains that small differences in the hourly commitment and dispatch levels can compound in subsequent hourly solutions, leaving the final solution set for a day significantly different from the original market solutions. As such, the MMU reran the simulations and compared the actual output to the validation case. The MMU discarded market days from the study, where the hourly production costs fell outside a 95% coefficient of determination between validation case and actual results. The MMU discarded approximately 8% of the market periods that fell outside the tolerance range.[102] The remaining days averaged a 99.5% coefficient of determination when comparing the hourly production costs in the validation solution to the original solution.[103]

<u>Scenario 2 – Units Elect "Market" Status</u>
Scenario 2 started with the validation cases performed in Scenario 1, and the MMU made a number of changes to the validation data set prior to executing Scenario 2. The MMU included the following changes to the validation data set: (1) resources that were offered in a self-commitment status were set to market status; (2) units were de-committed at the start of each study period; and (3) units were treated as having met their minimum down time before each continuous study period to allow the immediate commitment of units by the market engine. The MMU explains that Scenario 2 represent the market software's optimal solution given the current market structure without self-committed generation. Scenario 2 results increased the marginal energy prices in excess of 20% or roughly \$6 per MWh average across all hours.[104] The resulting increase demonstrates the price suppressing effects of self-commitment. While market pricing increased, the production costs increased roughly 8%, or more than \$22,000 per hour.[105] <u>The MMU</u>

[99] *See Id*, page 35.
[100] *See Id*, page 36.
[101] *See Id.*
[102] *See Id.*
[103] *See Id.*
[104] *See Id*, page 37.
[105] *See Id.*

concludes that Scenario 2's results suggest that the current market software cannot more efficiently commit and dispatch all available units in the absence of self-commitment.[106] (Emphasis Added)

Scenario 3 – Units Elect "Market" Status & Optimize Long Lead Times

Scenario 3 expands on the validation modifications of Scenario 2 and lengthens the day-ahead optimization window simulating the lengthening of the optimization period of the day-ahead market. Scenario 3 was the MMU's attempt to create a multi-day economic unit commitment. Scenario 3 addresses one of the current limitations of the market software – optimizing long-lead time resources. Long-lead time resources with high start-up costs tend to be uncompetitive, in part, because of the duration of the current market optimization window. Lengthening the window by 24 hours resolved a majority of these cases. The MMU notes that the length of the optimization window is not configurable in the current software. In order to simulate an increased optimization window, the MMU decreased the start-up times greater than 23 hours to 12 hours allowing the current day-ahead market software to commit the resource in a manner that simulates a lengthened economic unit commitment mechanism.

When compared to the validation scenario, Scenario 3 resulted in an increase to the average system marginal price of approximately $2 per MWh or an average of roughly 7.3% across all hours.[107] While the system marginal price in Scenario 3 declined when compared to Scenario 2, Scenario 3 resulted in a reduction to the average production costs by $1,750 per hour or an average of 0.5% when compared to the validation scenario.[108] The MMU concluded the results of Scenario 3 suggest that a purely economic commitment model, if able to consider and commit resources with long lead times, would lead to higher market pricing with more accurate investment signals while potentially reducing the total system production costs. Given this result, the MMU would prefer the results of Scenario 3 when compared to Scenario 2.[109]

The Scenario 3 optimization resulted in a change in dispatch quantities, which the MMU detailed in Figure 6-3: Scenario 1 vs Scenario 3, dispatch megawatts by fuel type.[110] Here Staff highlights some of the key changes in dispatch. First, Scenario 3 resulted in coal resource awards decreasing by roughly 7% when compared to the validation scenario that allowed the self-commitment of coal resources. Second, natural gas supply and virtual energy replaced the majority of the reduction in coal while the increase in wind energy awards was minimal. The MMU discussed the Scenario 3 impact in virtual energy rewards as follows:

> Because changes in self-commitment affect prices, and virtual participation is based on projected prices, we expect virtual trading behavior to also change. However, we are unable to simulate how virtual participants might adapt their behavior in the analysis.[111]

Furthermore, the MMU discusses the impact of the Scenario 3 self-commitment stating,

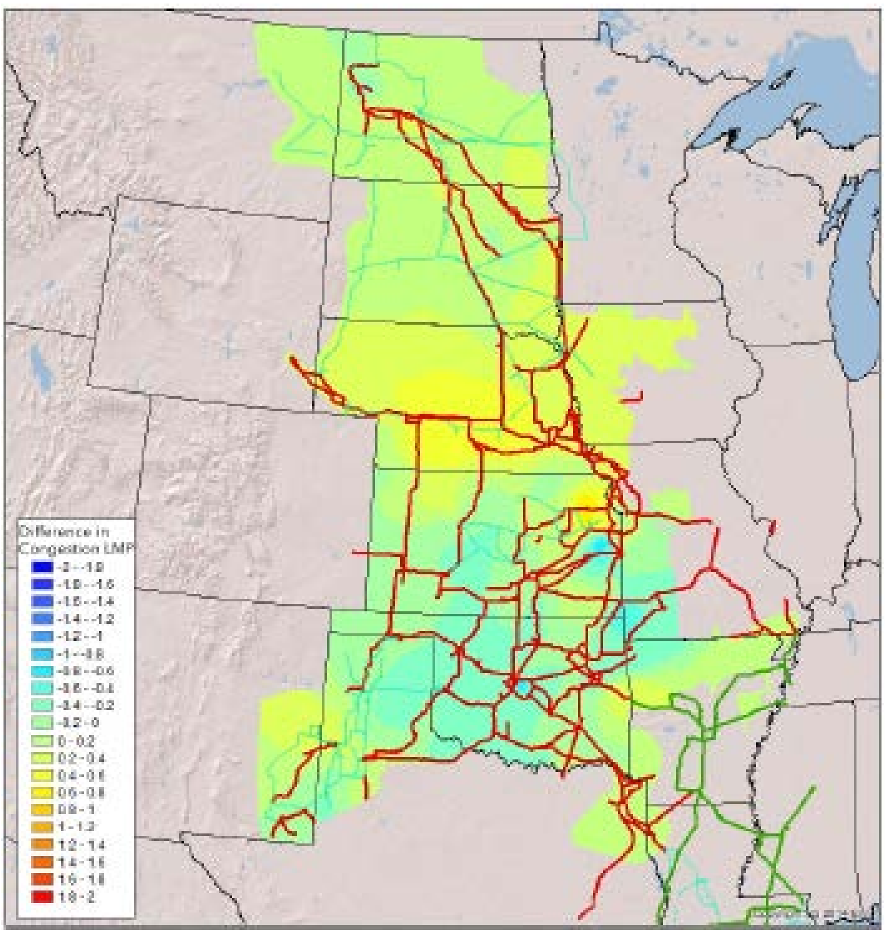
> Any structural change to the SPP market is likely to cause a redistribution of marginal generation that can have far-reaching impacts on congestion, local pricing, and congestion

[106] *See Id.*
[107] *See Id.* page 39.
[108] *See Id.*
[109] Scenario 3 methodology is consistent with the HITT's recommendations to evaluate a market enhancement for multi-day unit commitment, which the MMU supports.
[110] *See* MMU Whitepaper, Figure 6-3: Scenario 1 vs Scenario 3, dispatch megawatts by fuel type, page 40.
[111] *See Id*, page 40.

> hedging products. In order to visualize, the net congestion differences between the original market solution and this Scenario, we graphed the difference in the marginal congestion component (MCC) of the locational marginal priced over the study period.
>
> Generally, congestion reflects supply and demand relationship between producers and consumers in a given area. When an area is over-supplied with generation, congestion prices tend to be lower. Likewise, an area is oversupplied with generation will tend to have while an oversupplied area tends to have higher congestion prices.[112]

In order to illustrate the net congestion differences between the original market solution and Scenario 3, the MMU graphed the difference in the MCC contained in the LMP over the study period. The MMU's graph is plotted over the SPP footprint to better illustrate the congestion fluctuations and is contained in Figure 6-4: Scenario 1 vs. Scenario 3 Comparison, Difference in Congestion Costs. Higher congestion prices (yellow and orange) indicate increase in prices from the validation Scenario 1 to Scenario 3, and lower prices (green and blue) reflect price reduction in Scenario 3 relative to the validation Scenario. Staff included the MMU's illustration of congestion cost differences included in MMU Whitepaper Figure 6-4 for reference in discussing the congestion analysis below.[113]

Scenario 1 and Scenario 3 Comparison, Difference in Congestion Costs



[112] *See Id.*

[113] *See Id,* Figure 6-4: Scenario 1 vs. Scenario 3 Comparison, Difference in Congestion Costs, page 41.

Changes in congestion prices ranged between a reduction of $1 per MWh and an increase of $1 per MWh over the study period.[114] The majority of the supply reduction occurred in coal dominant regions of the footprint. As coal units were replaced by gas-fired generation from the southern portion of the footprint, the MMU explains that congestion costs around coal facilities increased whereas congestion costs decreased around gas-fired generation.[115] In comparison to the validation set, Scenario 3 produced mixed results in Kansas with increases and decreases to congestion costs throughout certain regions of the state. The eastern portion of Kansas and southern regions around major population centers resulted in increases to congestions costs ranging from $0.20 to $1.00. The central portions of Kansas mostly experienced reductions ranging from reductions of $0.60 to increases of $0.20. The western portions of Kansas varied with increases of up to $0.40 in Northwest Kansas while the rest of Western Kansas ranged from slight decreases of $0.20 to increases of $0.20. Any changes in congestion pricing would affect TCR revenue generated along various transmission pathways and would alter the congestion costs paid to serve retail load. If SPP developed a multi-day optimization for unit commitment, the market impact of the restructuring of unit offers, economic dispatch, and congestion costs should be viewed holistically at the utility level, taking into account increases in the marginal energy price, decreases in production costs, and increases or decreases to congestion costs and TCR revenue.

<u>Key Takeaways from the MMU Study</u>

The MMU's empirical study demonstrates that self-committed coal units continue to produce a significant percentage of SPP's energy volume and highlights the MMU's concerns about market inefficiencies arising from price and investment signal distortion. Generally, the MMU has taken a proactive approach in advocating for market enhancements that provide market participants and SPP operators the tools necessary to lower the incidences of self-commitment and manage rising market uncertainty and negative pricing intervals. The MMU's simulation study details the price suppressing impact of self-commitment and demonstrates the software limitations in the unit commitment optimization. These limitations contribute to the self-commitment practices of market participants and increases the frequency of self-commitment for regional coal units. Scenario 2 simulated the market impact of moving all resources to a market-commitment status utilizing the current market software. The Scenario 2 simulation resulted in significant increases to marginal energy prices and regional production costs. By increasing the system's production costs, the Scenario 2 simulation demonstrates that the utilities' concerns regarding the effectiveness of the unit commitment optimization are warranted, in particular for resources with long lead times and high start-up costs. Scenario 3 simulated a lengthened optimization window resulting in increases to the marginal energy price and slight reductions to the regional production costs. The simulation results for Scenario 3 indicate that a multi-day unit commitment model may further optimize SPP's regional production costs while limiting the distortion of pricing and investment signals.

The MMU Whitepaper provided a detailed review of the self-commitment practices of market participants and highlighted the progress made by market participants in reducing self-commitment of resources in the SPP IM. The MMU's resettlement simulations explored the limitation in the SPP market model and evaluated a market enhancement for multi-day unit

[114] *See Id,* page 41.
[115] *See Id.*

commitment. Staff supports the evaluation of a multi-day unit commitment optimization to provide utilities an expanded tool set to manage unit commitment. The next section of Staff's Report will analyze the Sierra Club's research on the ratepayer impact of self-commitment and detail the Sierra Club's recommendations to regulators and operators of regional energy market to limit the negative effects of self-commitment on captive ratepayers of vertically integrated utilities.

V. Sierra Club's Analysis on the Ratepayer Impact of Coal Subsidization

Throughout 2019, the Sierra Club released numerous studies[116] that analyzed the use of coal facilities and unit commitment decisions of utilities in wholesale energy markets. While Staff has reviewed each of the Sierra Club's studies, Staff's analysis will primarily focus on the Sierra Club's study "Kansas Pays the Price". Staff will discuss the Sierra Club's analysis performed in "Backdoor Subsidies for Coal in SPP," and "Playing with Other People's Money," at a high-level and highlight the key findings in each study. Across its studies, the Sierra Club's analysis primarily focused on the economic effects of self-commitment and its impact on captive retail customers and other renewable generation resources. The Sierra Club's studies touched on the environmental impacts resulting from the out-of-merit dispatch of self-committed coal units, which can lower air quality or increase carbon emissions that drive climate change; however, the environmental impact analysis was not the primary focus of its research studies.

Sierra Club's analysis in "Kansas Pays the Price" examined the market performance of Evergy's three large coal units. This study contributed more directly to Staff's report in analyzing the ratepayer impact of Evergy's self-commitment practices for managing its Kansas coal fleet. In each of its studies, the Sierra Club's analysis focused on the market effects that result from out-of-merit dispatch of self-committed coal units and highlighted the impact of regulatory mechanisms that guarantee the cost recovery of excess production costs from captive retail ratepayers. The Sierra Club also addressed issues that Staff highlighted throughout its report, including the suppression of energy market prices; the re-ordering of economic dispatch; and the market effects of pricing and investment signal distortion. In particular, the Sierra Club focused on the market effects that self-committed coal units have on renewable generating units. The Sierra Club detailed that self-committed coal units can displace lower cost wind resources resulting in reduced production output of the unit, which lowers the revenue and investment tax credits received by the unit. Additionally, renewable units will receive less revenue per unit of output due to the price suppressing effects of self-commitment. The Sierra Club reasoned that the market pricing and investment signal distortion from self-committed units could impede investors from developing future renewable generation projects. Finally, the Sierra Club raised its concerns that the vertically integrated market structure of SPP and other RTO/ISOs lacks sufficient incentive mechanisms and customer protections to prevent the uneconomic dispatch of coal assets.

<u>Sierra Club's Study - Backdoor Subsidies for Coal in the SPP</u>

In its Study "Backdoor Subsidies for Coal in the Southwest Power Pool", the Sierra Club explored how integrated utility rate structures incentivize inefficient operations of coal resources. Sierra Club argued that captive ratepayers are essentially subsidizing coal units that are uneconomic in

[116] In 2019, Sierra Club released three studies including: (1) Kansas Pays the Price: A Comparison of Coal Plants and Renewable Energy for Electric Consumers of Evergy, KCP&L, and Westar; (2) Backdoor Subsidies for Coal in the Southwest Power Pool; and (3) Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets.

the SPP IM by passing on the cost of out-of-merit dispatch via fuel surcharges instead of purchasing power from lower cost resources available in the SPP IM.[117] The Sierra Club argued that the complex regulatory structure and general lack of transparency in vertically integrated markets created a system where customers buffer and fill in gaps for market losses by integrated utilities.[118] Furthermore, the Sierra Club asserted that a proper functioning wholesale electric market would not incent inefficient market behavior, which results in market price suppression and the displacement of lower cost generating units.[119] From a market perspective, the Sierra Club argued that integrated utilities are free to self-commit, self-schedule, or under-bid their short-run marginal costs irrespective of the underlying economics of operating their coal resources, which essentially creates a back-door subsidy that captive ratepayers are funding.[120] Finally, the Sierra Club reasoned that utilities have an obligation to provide the lowest-cost power to retail customers; and therefore, retail consumers should not be required to make utilities whole for the uneconomic dispatch of their coal resources.[121]

Sierra Club's Study – Playing with Other People's Money

In its study "Playing with Other People's Money", Sierra Club explored the operation and dispatch of coal units by regulated utilities compared to merchant operators of coal units and examined the market losses of regulated utilities coal assets. When comparing the operational data of regulated and merchant coal units to the optimal economic dispatch of the resources, Sierra Club found that, as a general matter, merchant-operated coal units modeled closer to optimal economic dispatch than their regulated counter-parts.[122] Overall, the Sierra Club observed that merchant plants' actual dispatch are better aligned with market prices than regulated coal units operated in the same RTO/ISO.[123] Additionally, Sierra Club observed that the dispatch of merchant-operated units responded to falling market prices by reducing output, while regulated coal units were dispatched downward far less than merchant-operated coal resources.[124] As part of its research study, the Sierra Club estimated that the net energy market losses[125] from SPP regional coal units totaled $447.5 million from 2015 – 2017, with nearly all losses coming from regulated utility assets.[126] Further, Sierra Club estimated that the net market losses[127] from utility coal assets totaled $1.28 billion in SPP over the same period, with approximately 85% of losses attributable to regulated utility assets.[128] Based on its review of the market data, the Sierra Club concluded:

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[117] *See* Backdoor Subsidies for Coal in the Southwest Power Pool, page 2; https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf.
[118] *See Id,* page 5.
[119] *See Id,* page 13.
[120] *See Id,* page 29.
[121] *See Id.*
[122] *See* "Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets," page 12; https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.
[123] *See Id,* page 12.
[124] *See Id.*
[125] Net Energy Losses refers to the differential between total revenues received on the energy market (only) and production costs (fuel and variable O&M.).
[126] *See Id,* page 15.
[127] Net market loss refers to the differential between total revenues from both the energy and capacity markets, less production costs and fixed O&M costs. Sierra Club did not estimate incremental losses due to ongoing capital expenditures.
[128] *See* Playing with Other People's Money, page 15.

> Overall, [the market data] is clear that regulated coal units and merchant units have a substantially different pattern of dispatch in market regions compared to merchant coal units. Namely, over-commitment and/or out-of-merit operation, and the subsequent loss of net market revenue, is almost exclusively constrained to coal units owned by regulated utilities. In contrast, merchant coal-burning plants reduce dispatch and commitment in response to low energy prices, thereby preserving net positive market revenue.[129]

The Sierra Club noted its research addresses a long-standing argument of regulated utilities: that the market-commitment of their coal resources is limited by the operational constraints of the units and the lack of a multi-day market.[130] Based on the study results, the Sierra Club concluded that merchant-operated coal units have avoided the excessive losses of regulated units within the same regional energy market and/or retired uneconomic coal units to limit losses.[131] Furthermore, the Sierra Club implored regulatory commissions to further analyze unit commitment decisions of coal units and modify the incentive structure for regulated utilities to operate coal units only when the market-clearing price exceeds the production costs of the underlying asset.[132] The Sierra Club explained that the current regulatory structure in vertically integrated markets incentivizes inefficient market behavior and contended that Commissions should disallow the excessive fuel costs if a utility fails to demonstrate that it has dispatched its coal resources economically.[133] Sierra Club recommended that in the absence of a multi-day market, integrated utilities should develop a consistent and transparent set of practices for avoiding operations and commitment of coal resources through persistent periods of low wholesale energy prices.[134] The Sierra Club clarified these standards should rigorously assess the cost associated with unit cycling and clearly seek to minimize short and long-term costs.[135] Finally, Sierra Club advocated that, in absence of State Regulatory Commission actions to modify uncompetitive bidding practices of its regulated utilities, SPP should require market participants to market-commit resources to achieve the full economic dispatch of system resources and place reasonable requirements on the content of market bids to curb uneconomic bidding practices.[136]

Kansas Pays the Price

In "Kansas Pays the Price", the Sierra Club examined the operation of three of Evergy's large Kansas coal facilities: Jeffrey Energy Center, Units Nos. 1 – 3, La Cygne Unit Nos 1 & 2, and Lawrence Energy Center Units Nos. 4 & 5. Sierra Club's witness Paul Chernick presented a similar style of analysis examining the market revenue generated from SPP sales and the all-in operating costs of Westar's coal facilities in Westar's most recent rate case in Docket No. 18-WSEE-328-RTS.[137] In the "Kansas Pays the Price" study, Sierra Club discussed the transition away from fossil fuel coal plants and the growth of wind resources in the SPP region. In 2018, Kansas was one of the top wind producing states in the country, and had a larger percentage of its

[129] *See Id*, page 16.
[130] *See Id*, page 22.
[131] *See Id.*
[132] *See Id.*
[133] *See Id.*
[134] *See Id.*
[135] *See Id.*
[136] *See* Backdoor Subsidies for Coal in the Southwest Power Pool, page 30.
[137] *See* Rebuttal Testimony of John Bridson for Westar's response to the analysis provided by Sierra Club's witness Paul Chernick.

power generated from wind (36%) than any other state.[138] From 2008 – 2018, Sierra Club pointed out the electricity generated by Evergy's coal fleet has dropped by 50%; however, during this time period, Kansas retired approximately 6% of its overall coal capacity leaving utilities with increasing under-utilized assets.[139] Sierra Club stated that the average annual capacity factor for Evergy's coal units have fallen from 71% in 2009 to 50% in 2018, which Sierra Club sees as an indication that coal units are less competitive in the regional wholesale energy markets.[140]

In the report, the Sierra Club examined the variable and fixed costs to operate and maintain Evergy's coal facilities and detailed the revenue deficiencies from the sale of energy in the SPP IM from 2015 – 2018. The Sierra Club calculated net revenue by using the historical energy hub price for each hour in which Evergy's coal units were operated and then, compared the revenue against the reported production cost of Evergy's coal units (fuel, water and chemical re-agents, and variable operating expenses) and the fixed cost to operate the facilities (labor and maintenance costs). Sierra Club's methodology omitted the large irregular capital expenditures that require periodic replacement or future environmental compliance spending and the value of any capacity benefit of the units. Sierra Club explained that SPP does not operate a capacity market, and the capacity value of the units is not likely to be substantial due to the excess capacity in the SPP market. Using this methodology, Sierra Club's historical assessment of Evergy's Kansas coal fleet resulted in a loss of $266.7 million over the study period.[141] The table below provides a breakdown of the net revenue at Evergy Kansas coal facilities provided in the Sierra Club's study.[142]

Market Energy - Net Revenues at Evergy Kansas Coal Plants 2015 - 2018.*					
Unit	2015	2016	2017	2018	Total
Jeffrey Energy Center 1	-$2.8	-$12.6	-$9.2	$2.2	-$22.3
Jeffrey Energy Center 2	-$10.0	-$17.3	-$10.6	$1.9	-$36.1
Jeffrey Energy Center 3	-$9.2	-$11.9	-$12.6	-$1.7	-$35.4
La Cygne 1	-$26.4	-$19.9	-$32.7	-$11.0	-$90.0
La Cygne 2	-$25.9	-$21.2	-$30.0	-$0.8	-$77.9
Lawrence 4	-$2.8	-$1.6	-$0.4	$4.6	-$0.2
Lawrence 5	-$6.8	-$4.8	-$1.7	$8.5	-$4.8
Total	**-$83.9**	**-$89.2**	**-$97.2**	**$3.7**	**-$266.7**
* $ in Millions					

Sierra Club's assessment also included a forward-looking analysis for the facilities. Sierra Club projected the market price of energy at the relevant SPP pricing nodes, as well as the cost of coal, operations and maintenance expense, and incremental capital expenditures.[143] Sierra Club projected costs forward from 2020 – 2039 and assessed the net revenue of each unit. Sierra Club projected that La Cygne and Jeffrey units would incur revenue deficiencies of $847 million while

[138] *See* Sierra Club's study "Kansas Pays the Price" page 1.
https://coal.sierraclub.org/sites/nat-coal/files/2071_Kansas-Pays-Price-Evergy-Whitepaper_06_web.pdf.
[139] *See Id.*
[140] *See Id*, page 2.
[141] *See Id*, page 3.
[142] *See Id*. Staff reproduced Table 1: Market Energy Net Revenues at Evergy Coal Plants from 2015 – 2018.
[143] *See Id*, page 9. The Sierra Club provided a detailed overview of its calculation methodology for its forward-looking analysis in the Appendix of the report.

Lawrence produced a net present value benefit of $54 million over the next two decades.[144] In its analysis, the Sierra Club studied the activity of the La Cygne 1 unit by looking at the average market price of energy compared to unit's production costs (fuel and variable O&M) and the capacity factor of the plant over-time.[145] Based on its analysis, the Sierra Club concluded that the La Cygne 1 unit only produced positive revenues in a few months of the year, which has led to Evergy's seasonal operation of the unit during winter and summer peaking months.[146] For historical years 2015 – 2017, the La Cygne 1 effectively ran at an operating loss when it remained online in shoulder months.[147] In the analysis of the La Cygne 1 unit, the average production costs were approximately equal to the average market price; leaving ratepayers to cover the substantial fixed cost of labor, maintenance and on-going capital improvements.[148] The Sierra Club concluded that if La Cygne 1 unit were a privately owned or independent generator, the unit could not sustain the losses or justify on-going operations.[149] Additionally, the Sierra Club asserted that Evergy's customers bear the full cost of operating Evergy's coal fleet, and the market performance of the coal facilities is strongly indicative of how much Kansas ratepayers are losing.[150] Sierra Club concluded that no rational third-party would acquire Evergy's coal plants at a positive value.[151]

The Sierra Club study examined the Net Present Value (NPV) and Levelized Cost of Energy (LCOE) for the coal units. The LCOE is a calculation of the necessary revenue needed per MWh of generation sold for a power plant to break-even, given the fuel cost, operations, maintenance, and capital expenses. The LCOE provides an indicator for a settlement price for a long-term generation contract (Purchase Power Agreement (PPA)) that would allow the seller to recoup the full cost of providing electric service from the buyer. Sierra Club's calculation of the NPV and the LCOE for each of Evergy's coal units included in the study can be found in the table below.[152]

Net Present Value (NPV) and Levelized Cost of Energy (LCOE) for Coal Units			
Coal Unit	NPV (2020 -2039)*	NPV ($/kw-year)	LCOE ($/MWh)
Jeffrey Energy Center 1	-$295 m	-$20	$57
Jeffrey Energy Center 2	-$242 m	-$18	$54
Jeffrey Energy Center 3	-$147 m	-$10	$44
La Cygne 1	-$89 m	-$6	$40
La Cygne 2	-$74 m	-$5	$40
Lawrence 4	$9 m	$4	$37
Lawrence 5	$45 m	$6	$36
* Net Present Values are calculated in millions of 2020 dollars.			

[144] *See Id*, page 4.
[145] *See Id.*
[146] *See Id.* From 2014 – 2018, Sierra Club's production costs (fuel and variable O&M) for the La Cygne 1 Unit ranged from approximately $19 to $23 per MWh, and SPP market pricing ranged approximately $13 to $34 per MWh.
[147] *See Id.*
[148] *See Id.*
[149] *See Id.*
[150] *See Id*, page 5.
[151] *See Id.*
[152] *See Id.* Staff reproduced the NPV and LCOE found in Table 2: Net Present Value and Levelized Cost of Energy for Coal Units in the Sierra Club study.

For comparison purposes, Sierra Club stated the PPA prices were as low as $14 per MWh for wind units and $24 per MWh for solar units through Q1 of 2019.[153] Sierra Club noted that the higher levelized costs for coal units further illustrated that Evergy's ratepayers are unnecessarily paying to generate power and passing those costs onto Kansas ratepayers.[154] Furthermore, Sierra Club calculated that Kansas ratepayers covered revenue deficiencies of $267 M at Evergy's three large coal units relative to energy market pricing from 2015 -2018, and consumers are just beginning to pay for the capital recovery for La Cygne retrofit totaling $1.23 billion completed in 2015.[155] Sierra Club noted that recent concerns have been raised from Kansas lawmakers regarding the increasing cost of retail electricity rates in Kansas.[156] Sierra Club contended its analysis and calculation of the net operating losses of operating Evergy's coal units were conservative in nature and demonstrated that the majority of Evergy's coal power results in unnecessarily high energy costs for Kansas families, businesses, and other electric consumers.[157]

Sierra Club recommendations resulting from the study included the following:

1. Evergy should begin planning with transparency via its new Integrated Resource Planning process, and the KCC should provide stringent oversight of that planning process.[158]
2. Evergy should conduct a unit-by-unit analysis of its coal fleet to evaluate costs and market conditions facing those units so the utility can identify the retirement date for each unit that is economically optimal for captive customers.[159]
3. Evergy should issue a competitive, all-source Request for Proposal (RFP) for capacity and energy, including wind, solar, storage, and demand-side resources such as energy efficiency and demand response.[160]
4. Evergy should be held accountable when market prices for the uneconomic operations and dispatch costs of its coal fleet. Evergy should be purchasing market energy – not operating its coal plants.[161]

<u>Staff Analysis of Sierra Club's Findings</u>
Sierra Club's research adds to the conversation of how to address Evergy's regionally high retail rates. Additionally, the research is pertinent to upcoming KCC determinations on resource planning in Evergy's first Triennial IRP docket slated for early 2021[162], and the investigation into the Sustainability Transformation Plan (STP) opened in Docket No. 21-EKME-088-GIE (21-088

[153] *See Id*. Using the Sierra Club's source, levelized PPA prices for wind assets were $17.5/MWh at the North Hub and $16.3/MWh at the South Hub. Levelized PPA prices for solar assets were $29.3/MWh at the North Hub and $25.9 at the South Hub in Q2 of 2020; https://leveltenenergy.com/blog/ppa-price-index/q2-2020/.
[154] *See Id.*
[155] *See Id*, page 6.
[156] *See Id.*
[157] *See Id.*
[158] *See Id*, page 8.
[159] *See Id.*
[160] *See Id.*
[161] *See Id.*
[162] *See* Order approving the IRP and Capital Plan process in the 19-KCPE-096-CPL Docket; https://estar.kcc.ks.gov/estar/ViewFile.aspx/20200206105827.pdf?Id=da24762e-a6b9-4288-9cde-09ab47dac275.

Docket).[163] On August 5, 2020, Evergy announced its Sustainability Transformation Plan (STP). The STP was driven by an agreement between Evergy and Elliot Management to consider a Modified Standalone Plan that would effectively cut operating and maintenance expenses and increase capital expenditures; or, in the alternative, to facilitate a Merger Transaction to increase the long-term value for Evergy's stakeholders.[164] Evergy's press release announcing the STP discusses the opportunities for decarbonization. Renewable deployment depends on the outcome of a stakeholder engagement process and updates to the long-term energy plan.[165] In the press release, Evergy states the Company has the potential to reduce carbon emissions by 85% over its 2005 levels by 2030; however, the pace of decarbonization will be defined in collaboration with the Company's stakeholders.[166] Evergy is currently targeting an 80% reduction of CO_2 emissions 2050.[167] The long-term market outlook for Kansas's coal fleet will be a key component of these upcoming dockets and accelerated retirement of the units will likely be evaluated. Many of the assertions made by the Sierra Club pertaining to the long-term economics of continued operation of Evergy's coal fleet are outside of the scope of this ACA Docket and are more appropriately evaluated in the context of Evergy's upcoming triennial IRP Docket and the general investigation into Evergy's STP in the 21-088 Docket.

The Sierra Club's all-in cost analysis (including both fixed and variable costs of operation) provides a starting place for looking at plant efficiency and determining whether market revenue can fully cover the total operating costs of the unit. This analysis is appropriate if the objective is to examine the long-term economic viability of the coal facilities to determine if the long-term operation of the unit is economically justified. Staff does not believe it is appropriate to evaluate whether coal units are covering their entire fixed cost of operation in an ACA proceeding and Sierra Club's methodology goes beyond the scope of the docket. This type of analysis is better employed in an IRP docket.

Sierra Club's analysis serves a starting point for examining the long-term operation of the unit by identifying a revenue deficiency for the unit. Upon identifying a revenue deficient asset, the analysis can be extended by asking whether the unit serves a reliability or capacity function. A peaking unit may be deficient in terms of market revenue; however, the cost justification may be the role it serves in handling the system peak or providing a local reliability function. If the asset serves a capacity/reliability function, then retiring the asset will require an investment in an alternative asset. Upon identifying the lowest cost replacement asset that can cover the capacity function of the existing asset, a cost-benefit calculation can examine the market revenue stream and total cost of the existing asset and compare the market revenue stream, the operation and maintenance expenses, and the necessary capital investment to construct the new asset. If a net benefit is produced, the asset can be scheduled for retirement and the new asset serves a net-benefit

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[163] *See* Order opening General Investigation to the Sustainability Transformation Plan (STP) in Docket No. 21-EKME-088-GIE filed on August 27, 2020; https://estar.kcc.ks.gov/estar/ViewFile.aspx/20200827103642.pdf?Id=f5e15fda-13af-464a-99b5-6b9db8e5926e.
[164] The KCC issued an Order opening an Investigation into the Agreement between Evergy and Elliot Management in Docket No. 20-EKME-514-GIE filed on June 18, 2020; https://estar.kcc.ks.gov/estar/ViewFile.aspx/20200618104632.pdf?Id=509dd85d-5964-4d3c-923d-1f2ba1811834.
[165] *See* Evergy's Press releases announcing STP, issued August 5, 2020; https://www.evergy.com/about-evergy/newsroom/2020/august/evergy-announces-sustainability-transformation-plan.
[166] *See Id.*
[167] *See Id.*

to the ratepayer. Due to the large capital outlay, and long asset lives, utility assets are recovered through utility rates over the life of the asset. If the existing asset has unrecovered net book value, the ratemaking treatment of the unrecovered investment should be included as consideration in a net benefit calculation.

While the Sierra Club's study indicates that revenue deficiencies exists at the Evergy coal units, the Sierra Club's study period may not accurately represent the impacts of the future on-going operations of the coal units. In recent years, Evergy has pursued a more aggressive market-commitment strategy for managing its coal fleet allowing the units to cycle in periods of low demand, which is discussed further in the Report & Recommendation. When you examine Sierra Club's estimated operating results at Evergy's Kansas coal units, Evergy earned a total net revenue of $3.7 million (absent capital maintenance costs) in 2018 when compared to net losses of approximately $97.2 million in 2017.[168] The key drivers of Evergy's operational results were its more aggressive offer strategy, which increased the cycling of its coal units over uneconomic operating periods, and an increase in the wholesale energy price of approximately 9% year-over-year. Increased cycling of baseload coal units is likely to be the new operating paradigm for the units going-forward, which can maximize the revenue potential of the units and minimize the cost of the assets to retail ratepayers.

[168] *See* Staff Table: Market Energy - Net Revenues at Evergy Kansas Coal Plants 2015 – 2018 for Sierra Club's estimates of net revenues for Evergy's coal units for 2017 and 2018, page 36.

CERTIFICATE OF SERVICE

19-KCPE-353-ACA

I, the undersigned, certify that a true and correct copy of the above and foregoing Notice of Filing of Staff 's Public Report and Recommendation was electronically served this 13th day of January, 2021, to the following:

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