QUARTERLY INDEPENDENT MONITORING REPORT
ON
DUKE ENERGY CAROLINAS, LLC

First Quarter 2018

Issued by:

POTOMAC ECONOMICS

Independent Market Monitor

April 30, 2018

CONFIDENTIAL MATERIAL REDACTED

Table of Contents

List of Figures

I. Overview

This transmission monitoring report evaluates the period from January through March 2018 for Duke Energy Carolinas, LLC (formerly Duke Power, a division of Duke Energy Corporation) ("Duke" or "the Company"). For the purpose of increasing confidence in the independence and transparency of the operation of the Duke transmission system, Duke proposed, and FERC accepted in Docket No. ER05-1236-00, the establishment of an "Independent Entity" ("IE") to perform certain functions relating to the Open Access Transmission Tariff ("OATT"). The transmission monitoring plan also calls for an "independent transmission service monitor". The MISO was retained as the IE, and Potomac Economics was retained as the independent transmission service monitor.

The scope of the independent transmission service monitor is established in the transmission monitoring plan. The plan is designed to detect any anticompetitive conduct from operation of the company's transmission system, including any transmission effects from the company's generation dispatch. It is also intended to identify any rules affecting Duke's transmission system that result in a significant increase in wholesale electricity prices or the foreclosure of competition by rival suppliers. As stated in the plan:

> The Monitor shall provide independent and impartial monitoring and reporting on: (1) generation dispatch of Duke Power and scheduled loadings on constrained transmission facilities; (2) details on binding transmission constraints, transmission refusals, or other relevant information; (3) operating guides and other procedures designed to relieve transmission constraints and the effectiveness of these guides or procedures in relieving constraints; (4) information concerning the volume of transactions and prices charged by Duke Power in the electricity markets affected by Duke Power before and after Duke Power implements redispatch or other congestion management actions; (5) information concerning Duke Power's calling for transmission line loading relief ("TLR"); and (6) the information provided by Duke Power used to perform the calculation of Available Transmission Capability ("ATC") and Total Transfer Capability ("TTC").

To execute the monitoring plan, Potomac Economics routinely receives data from Duke that allows it to monitor generation dispatch, transmission system congestion and the Company's response to transmission congestion, including its business activities. Potomac Economics also collects data from other sources, including OASIS data and market pricing data.

The purpose of this report is to present the results of our monitoring activities and significant events on the Duke system from January to March 2018. [1]

A. Independent Monitoring

Potomac Economics performs the monitoring function on a regular basis, and conducts periodic reviews and special investigations. Our primary monitoring is conducted through regular analysis of market data relating to transmission outages, congestion and system access. This involves data on transmission outages, transmission reservation requests, ATC, Available Flowgate Capability ("AFC"), TLR and curtailments or other actions taken by Duke to manage congestion. Analyses of this data aid in detecting congestion and whether market participants have full access to transmission service.

In addition to the regular monitoring of transmission outages and reservations, we also remain alert to other significant events, such as price spikes, major generation outages, and extreme weather that could adversely affect transmission system capability and give rise to the opportunity for anticompetitive conduct.

Our periodic review of market conditions and operations is based on data provided by Duke as well as other data that we routinely collect. Our review consists of four parts. First, we evaluate regional prices and transactions to provide an assessment of overall market conditions. Second, we summarize transmission congestion and the use of schedule curtailments in order to detect potential competitive problems (congestion is identified by schedule curtailments[2] on Duke's transmission system). Third, we evaluate the disposition of transmission service requests and flowgates to analyze transmission access and to detect events on the Duke system that require closer analysis. Finally, to monitor for anticompetitive conduct, we examine periods of congestion and evaluate whether Duke operating activities are consistent with competitive

[1] As allowed for in the monitoring plan, certain anomalous findings related to general market conditions, TSRs, TTC and transmission outages were shared with Duke to obtain clarification prior to submission to FERC and state Public Utility Commissions.

[2] When we refer to schedule curtailments, we include TLR events because curtailing schedules is the main method used under the TLR procedures to manage congestion.

conduct. The operating activities that we evaluate are wholesale purchases and sales, generation dispatch and availability and transmission availability.

In addition to our periodic reviews, we may be asked or we may deem it necessary to undertake a special investigation in response to specific circumstances or events. No such events occurred during the period covered in this report.

B. Summary of Quarterly Report

The following subsections summarize the findings of our monitoring of Duke's operations during the first quarter of 2018.

1. Wholesale Prices and Transactions

Prices. We evaluated regional wholesale electricity prices in order to provide an overview of general market conditions. Over the course of the study period, electricity prices fluctuated between $19 and $75 per MWh and remained correlated with load patterns and natural gas prices. Power prices peaked in the first week of January when prices rose as high as $75 per MWh, which was coincident with natural gas prices increasing to $127 per MMBtu.

Sales and Purchases. Duke engages in wholesale purchases and sales of power on both a short-term and long-term basis. [redacted]

2. Transmission Congestion

We used TLR events and schedule curtailments in the vicinity of Duke to identify periods of congestion. Duke manages transmission congestion with generation redispatch, transmission system reconfiguration, and schedule curtailments.[3] Of these, schedule curtailments have the most direct impact on market access and outcomes. During the period of study, there were no

3 We use the term "schedule" loosely in this context. It is actually NERC e-TAGs that are curtailed. Each e-TAG represents a physical sequence and time series of schedules. Therefore, one e-TAG may be comprised of multiple schedules. It is also possible for the same e-TAG to be curtailed more than once.

TLRs initiated by Duke and two schedule curtailments initiated by Duke. Other transmission operators initiated 167 curtailments, of which 80 were due to TLR events.

All curtailments, regardless of their basis, are important because they have the same impact on reducing transmission access. However, only schedules that are curtailed based on physical flow (including TLRs) are potentially influenced by Duke's operation of generation. We analyzed the impact of Duke's generation operations on the flow-based curtailments and found that uneconomic dispatch of Duke's generation did not significantly contribute to the curtailments.

3. Transmission Access

We evaluate the patterns of transmission requests and their disposition to determine whether market participants have had difficulty accessing Duke's transmission network. If requests for transmission service are frequently denied unjustifiably, this could indicate an attempt to exercise market power. The volume of approvals during the study period was higher than that of the prior quarter, and the volume of refusals during the study period was lower than that of the prior quarter. The approval rate continued to be high, averaging 99 percent. Given the high volume of service sold and the high level of approvals, we do not find a pattern in the disposition of transmission requests that indicates restricted access to transmission.

We evaluated the flowgates that caused Transmission Service Request (TSR) refusals. The largest contributor to TSR refusals that occurred during the period of study for daily and hourly service was the "AEP to Dominion", which is a PJM flowgate. For Duke flowgates, we compared calculated base flows from the ATC model builder process with real-time flows associated with a select group of TSR refusals and found calculated flows were not limiting transmission access by forecasting heavier flows than were seen in real-time.

4. Potential Anticompetitive Conduct

Wholesale Sales and Purchases. We examined real-time sales and purchases that were delivered during the period of study. We focused on intra-day bilateral contracts because these contracts best represent the spot price of electricity in markets served by Duke and are the means by which Duke would likely profit by raising wholesale electricity prices. Under a hypothetical exercise of market power, we would expect higher sales prices or lower purchase prices during periods when transmission congestion arises. We identified three days with transactions that may have potentially benefited from congestion during the period of study.

Generation Dispatch and Availability. We examined the joint dispatch of the combined Duke and Progress generation assets to determine the extent to which congestion may be caused or exacerbated by uneconomic dispatch. Congestion can occur even when Duke or any other utility dispatches its units in a least-cost manner. Such congestion does not raise competitive concerns. If an unjustified departure from least-cost dispatch ("out-of-merit" dispatch) occurs and contributes to congestion, further analysis is warranted to determine whether Duke's conduct raises competitive concerns.

Using an estimated supply curve, we analyzed Duke's actual dispatch to determine whether it departed significantly from what we estimate to be the most economic dispatch. We then evaluated the contribution of the out-of-merit dispatch to flows on congested transmission paths to determine if congestion was either created or exploited by Duke. Our investigation did not find any unjustified out-of-merit dispatch of generation that significantly contributed to congestion during the study period.

We also conducted an analysis of potential economic and physical withholding to further evaluate generation operations. Our measures of potential economic and physical withholding were not indicative of anticompetitive conduct. Evaluation of generation outage rates revealed no evidence that generation outages were associated with anticompetitive conduct.

Transmission Availability. The analysis of transmission outages is deferred to a special investigation since the necessary data was not received in time to be included in this quarterly report.

5. Conclusions

Our analysis indicated no potential anticompetitive conduct from operation of the company's generation.

C. Complaints and Special Investigations

No complaints were filed.

The special investigation that we initiated in the prior quarter to determine the cause of apparent inaccuracies in the ATC model builder process associated with one flowgate is still in progress as we continue to await the requested data.

We are also starting a new special investigation for this quarter to analyze transmission outages in the first quarter of 2018.

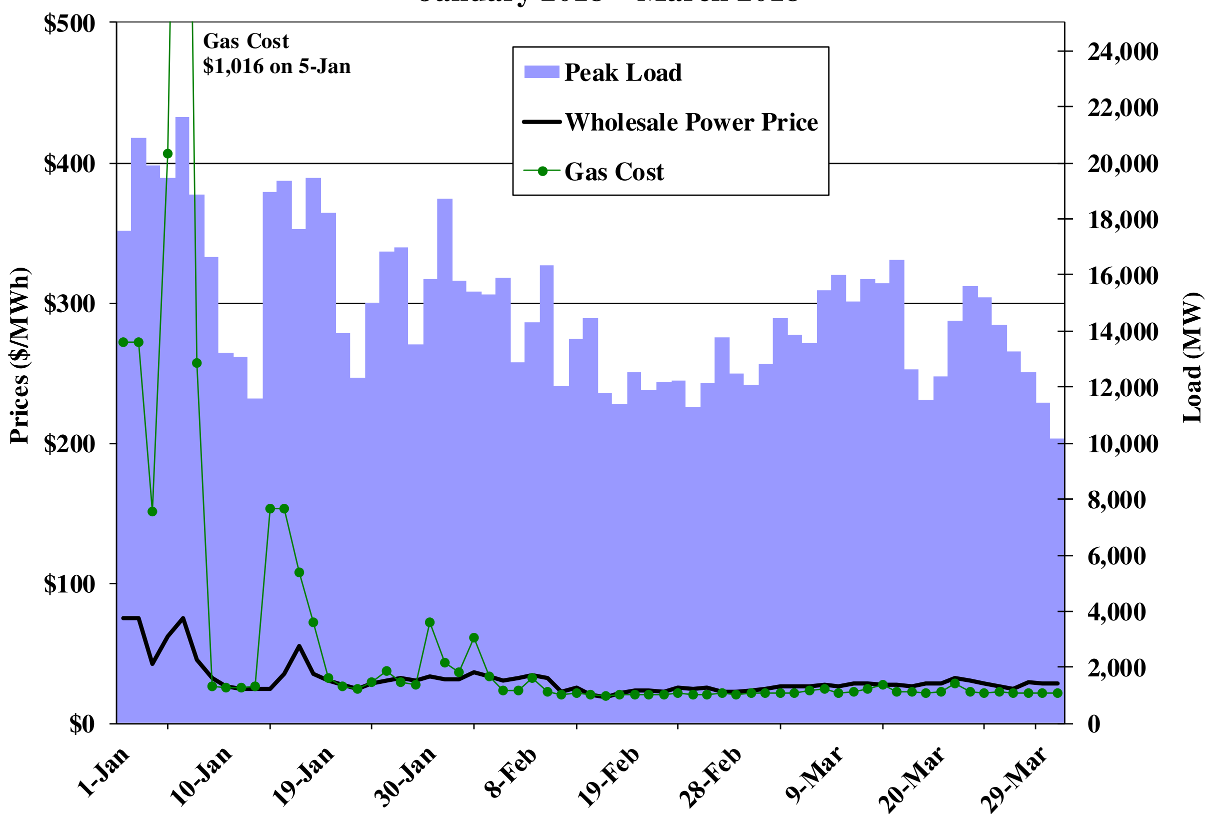
II. Wholesale Prices and Transactions

A. Prices

We evaluated regional wholesale electricity prices in order to provide an overview of general conditions in the market in which Duke operates. Although they are not definitive indicators of anticompetitive conduct, examining price movements can provide insight into specific time periods that may merit further investigation.

Duke is not part of a centralized wholesale market that produces transparent spot prices. Wholesale trading in the areas in which Duke operates is conducted under bilateral contracts. Bilateral contract prices are collected and published by commercial data services such as "S&P Global Market Intelligence", which we relied upon for this report. In seeking a representative index with trading volumes adequate to provide reasonable liquidity, we selected the day-ahead on-peak index "Into SOCO". Figure 1 shows the bilateral contract prices for "Into SOCO" as the Wholesale Power Price along with other market indicators.

Figure 1: Wholesale Power Prices, Peak Load, and Natural Gas Costs
January 2018 – March 2018

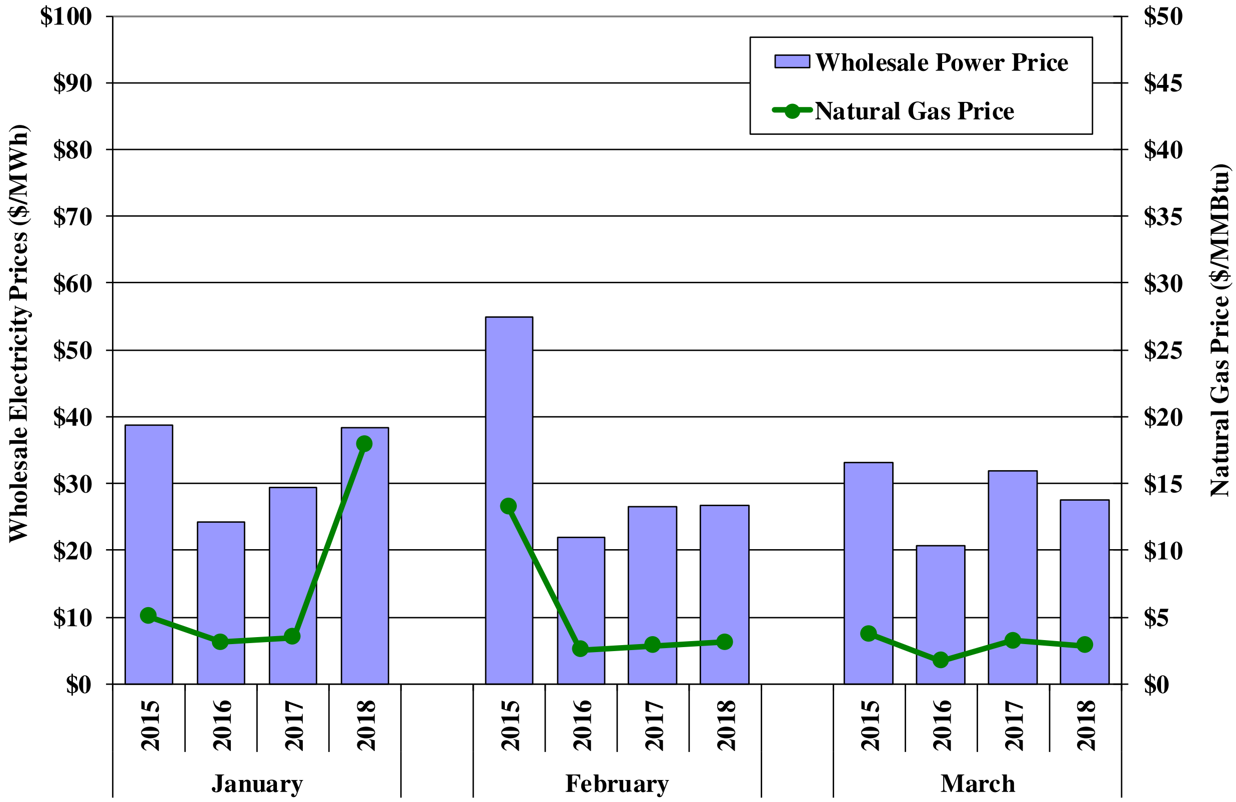


We show system load data because system load typically displays a positive correlation with power prices. We show natural gas costs because a natural gas-fired unit is most often the marginal unit supplying the grid, and because fuel costs comprise the vast portion of a generating unit's marginal costs. We used the daily price of natural gas deliveries by Transco at its Zone 5 location, a primary pricing point for natural gas purchases by Duke. We translate this natural gas cost to a power price by assuming an 8,000 btu/kWh heat rate. This roughly corresponds to the fuel portion of the operating cost of a natural gas combined-cycle unit, which should generally correspond to the competitive price for power.

Wholesale power prices ranged from approximately $19 to $75 per MWh over the study period and were correlated with load patterns and natural gas prices. As the figure shows, there were higher prices at the beginning of the quarter when the wholesale power price was $75 per MWh for several days in the first week of January. Loads varied during the study period with large swings in January. Loads were the highest on January 5 when the wholesale power prices were at their maximum, but the main driver of high pricing during this time period was natural gas costs. Natural gas costs exhibited high volatility in early January when cold ambient temperatures drove up demand and gas prices in the northern parts of the country. On January 5, natural gas prices rose to $127 per MMBtu.

The next analysis compares the average power price for each month in the study period with the corresponding month in the previous three years. Results are shown in Figure 2 along with the average of the daily Transco Zone 5 natural gas prices.

Figure 2: Trends in Monthly Power and Natural Gas Prices
First Quarter, 2014 – 2018



As the figure shows, power prices have generally been correlated with natural gas prices over time. Our evaluation of wholesale electricity prices in the Duke region leads us to pay particular attention to early January as we proceed through the other parts of our analysis.

B. Sales and Purchases

Duke engages in wholesale purchases and sales of power. These transactions are both firm and non-firm in nature. Figure 3 summarizes Duke's sales and purchase activity for trades that were delivered during the study period.

We consider only short-term trades (transactions taking place in the day-ahead or intra-day markets) because we are primarily interested in transactions that could have allowed Duke to benefit from any potential market abuse during this time period. Longer-term transactions generally occur at predetermined prices that would not be directly affected by transitory periods of congestion. Additionally, short-term transaction prices are good indicators of wholesale market conditions during periods of congestion.

Figure 3: Summary of Duke Sales and Purchases
January 2018 – March 2018

	Volume (MWh)
[redacted]	

As the figure shows, Duke's [redacted] In general, a market participant exercising market power would be a short-term net seller making short-term sales at high prices, or a short-term net buyer making short-term purchases at low prices. The fact that Duke's [redacted] In this context, we evaluate the prices of real-time transactions during congested periods in Section V.A in order to detect potential anticompetitive conduct.

III. Transmission Congestion

A. Overview

Duke is located in the SERC region of the North American Electric Reliability Council ("NERC") and is a certified Electric Reliability Organization. SERC is divided geographically into five sub-regions that are identified as Delta, Gateway, Southeastern, Central, and VACAR. For the establishment of Reliability Coordinators, VACAR is further divided into two intraregional coordination groups known as VACAR North and VACAR South. Duke is within the VACAR South coordination group along with five other balancing authorities: Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company, South Carolina Public Service Authority (Santee Cooper), Southeastern Power Administration, and Yadkin (a division of Alcoa Power Generation, Inc.).

Procedures to manage transmission congestion are implemented by the VACAR South Reliability Coordinator. The activities covered in these procedures include performing day-ahead and real-time reliability analysis, working with participants to correct System Operating Limit ("SOL") and Interconnection Reliability Operating Limit ("IROL") violations, and managing TLR events.

The VACAR South coordination group utilizes an "Agent" to perform RC tasks. Duke, in addition to being a member of the VACAR South coordination group, is contracted to serve as Agent to perform the duties of RC for itself and the other five VACAR South member companies. The transmission monitoring plan calls for monitoring Duke's operation of its transmission system to identify anticompetitive conduct, including conduct associated with system operations and reliability coordination.[4] Our monitoring is limited to conduct associated with Duke's transmission system and does not extend to Duke's RC activities as Agent for the VACAR South coordination group.

B. Transmission Congestion

We monitor Duke for potential anticompetitive operation of generation or transmission facilities that may create transmission congestion or otherwise create barriers to rival companies' access to

[4] See Transmission Service Monitoring Plan, Section 1.2.

the markets. Duke identifies congestion in the operating horizon through real-time contingency analysis ("RTCA"). In this process, operators monitor line-loadings to keep them within ranges so that a system outage or "contingency" can be sustained safely. If line-loadings exceed this safe range (called the system operating limit or "SOL"), then the lines are relieved[5] through a combination of generation redispatch, reconfiguration, schedule curtailments, and load reduction.[6]

Congestion between balancing authorities is monitored and managed through the use of TLR procedures. These procedures invoke schedule curtailments, system reconfiguration, generation redispatch and load shedding as necessary to relieve congestion by reducing flows below the first-contingency transmission limits on all transmission facilities.

Schedule curtailments or TLR events can constitute anticompetitive conduct if they are not justified. They cause an immediate reduction in market access that could affect market outcomes. Accordingly, these congestion events are the basis for our screening of Duke's generation and transmission operations.

For the purposes of our analyses, we consider two types of schedule curtailments. The first type is "flow-based curtailments," which are curtailments to accommodate the actual physical flows on facilities as identified by the RTCA. We include TLR events[7] as flow-based curtailments. The second type is "non-flow-based curtailments". Non-flow-based curtailments capture all curtailments that are taken for reasons other than relieving real-time flows on congested transmission elements. While non-flow-based curtailments have the same effects on market access as flow-based curtailments, these curtailments are not caused by the operation of generation.

During the period of study, there was one TLR in the region and four TLRs outside the region that resulted in the curtailment of 80 schedules that used Duke's transmission service. Duke did not initiate any of these TLRs.

5 Some contingency overloads do not require action to be taken because they do not have the potential to cause cascading outages, substantial loss of load or major equipment damage.

6 System reconfiguration actions may include opening tie line breakers, which can cause TTC to go to zero and induce schedule curtailments.

7 The types of TLR events that we include are 3a, 3b, 5a, and 5b.

There were also 87 non-TLR curtailments, two of which were initiated by Duke. These were schedule reductions initiated for various reasons including generation unit issues and reliability.

Even though Duke initiated only two curtailments during the quarter, Duke Operations could adversely impact the transmission network and lead other security coordinators to initiate curtailments. Accordingly, we evaluate all curtailments and TLRs that Duke could plausibly have affected through its operations. We call these "flow-based" curtailments. They do not include those curtailments associated with PJM ramp constraint events because Duke's generation or transmission assets do not contribute to PJM ramp constraints.

IV. Transmission Access

A primary component of the transmission monitoring function is to evaluate transmission availability on the Duke system. In this section, we evaluate access to transmission by analyzing the disposition of transmission service requests. The patterns of transmission requests and their disposition are helpful in determining whether market participants had unreasonable difficulty accessing Duke's transmission network.

We calculated the volume of requested capacity in the quarter. For example, if a request was approved in April for service in September, we categorize that as an approval for September. Because requests vary in magnitude and duration, we assign a total monthly volume (GWh) associated with a request, which provides a common measure for all types of requests. Hence, a yearly request for 100 MW has rights for every hour of the month for which the request spans, just like a monthly request. A request covering less than the entire month is assigned for each hour between its start and stop date.

Figure 4: Disposition of Requests for Transmission Service on the Duke System January 2018 – March 2018

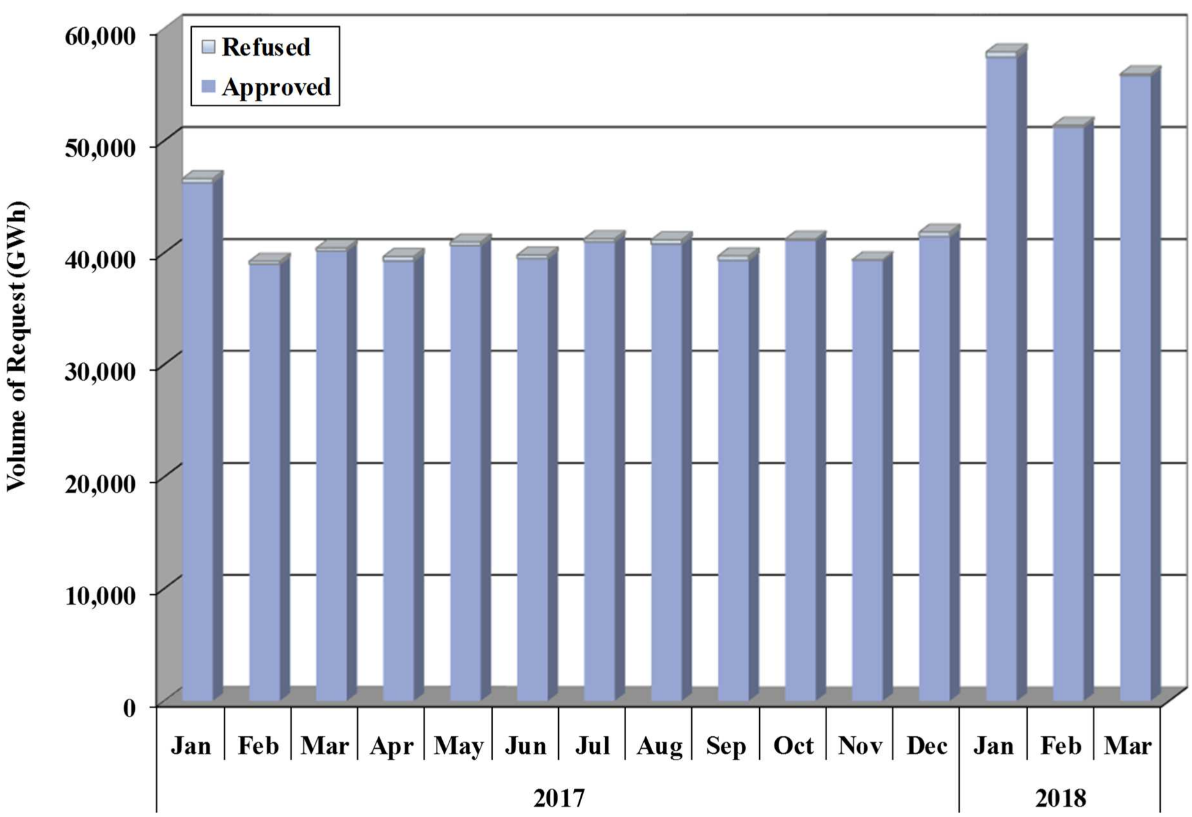


Figure 4 shows the breakdown of transmission service requests in each month from January 2017 through March 2018 and summarizes the disposition of the requests.

The total volume of approved requests during the study period was 164,494 GWh. The total volume of refused requests during the study period was 756 GWh. The volume of approved requests was greater than that of the prior quarter and of the same quarter of the prior year. The approval rate of transmission service requests has remained over 99 percent. Given the increase in the volume of approved requests and the low percentage of refused requests, we do not find evidence that Duke restricted access to transmission capability in the quarter.

To further evaluate the disposition of transmission requests, we compared the volume of transmission requests over the study period by increment of service to the requests from the corresponding period a year prior. This comparison is shown in Figure 5.

Figure 5: Disposition of Transmission by Duration of Service
First Quarter, 2016 – 2018

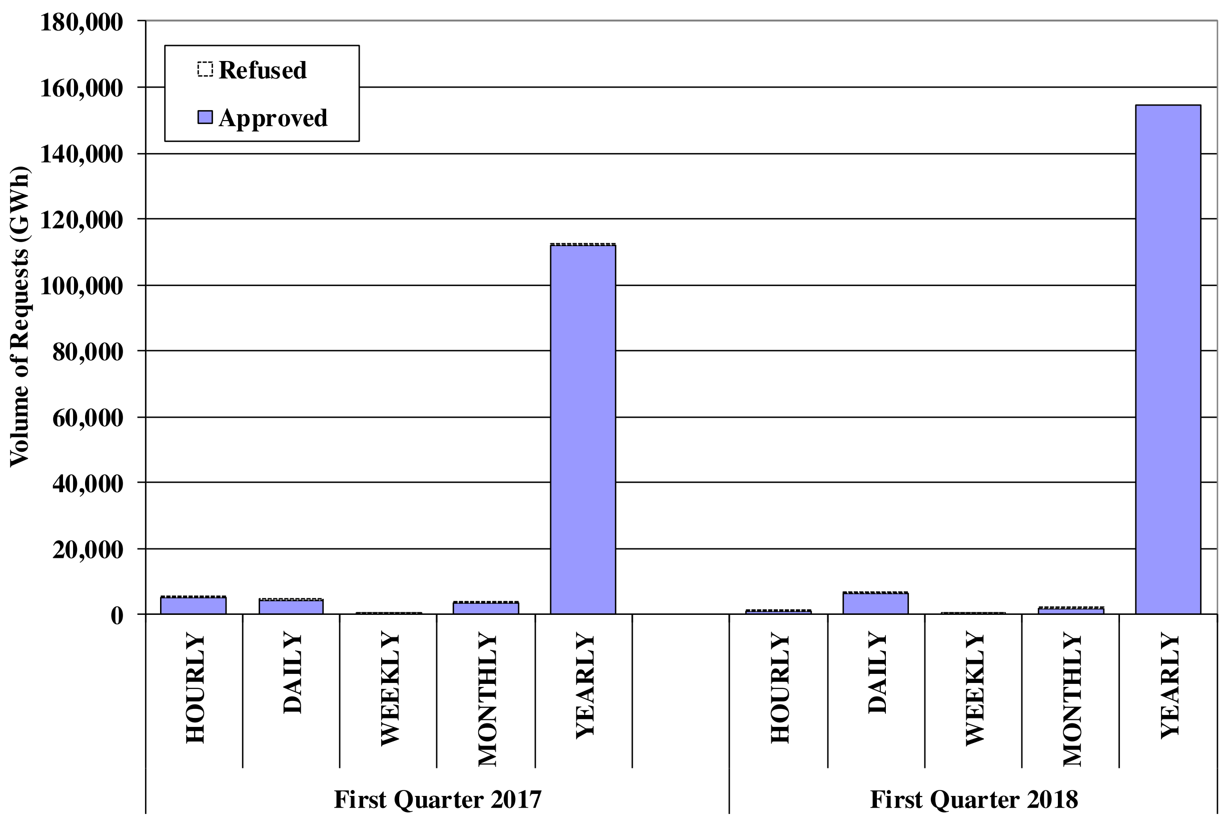


Figure 5 shows volumes of approvals and refusals from both the first quarter of 2017 and the first quarter of 2018 for all service increments. There are similarities in high volumes for yearly service and significantly lower volumes for shorter term service. The increase in approved volumes were mostly for yearly service, showing a thirty-eight percent increase. Fifty-eight percent of the refusals in the first quarter of 2018 were for monthly service and twenty-nine percent were for daily service. The conditions behind the refusals for daily and hourly service will be examined further in the key flowgates analysis that follows.

To further analyze transmission access, our next analysis focused on the set of key flowgates that most limit transmission access. In the AFC methodology used by Duke to assess transmission requests, transmission service is analyzed against the physical elements that the request impacts. Using the AFC methodology, specific physical facilities (flowgates) are identified across the balancing area and the adjacent balancing areas. The flows associated with the TSR on the flowgates are calculated as the product of the TSR capacity and the Transfer Distribution Factor (TDF). The TDF indicates the flow on each flowgate associated with the specific transfer between two areas. (Flows on a flowgate with TDFs below a minimal amount (3 percent or 5 percent) are set to zero in this process.) The TSR is only approved if it does not cause any flowgate to exceed its Total Flowgate Capability (TFC). In addition, for area to area transfers, the TSR is not approved if it does causes the contract path limit to be exceeded. The process takes into account load forecasts, transmission outages, generation outages, existing TSR rights and schedules.

This process may provide incentives for Duke to implement the AFC methodology in a way that reduces AFC and thereby excludes competitors. Therefore, we monitor this process by selecting and evaluating flowgates that were the basis of TSR refusals. We review the circumstances surrounding the AFC results to ensure that the results are proper and justified.

To provide a perspective of the interconnections of the balancing authorities that comprise the paths that use Duke's transmission service and which of these are in the VACAR South intraregional coordination group, see Figure 6 below. The acronyms have the following meanings:

- CPL: CPLE and CPLW refer to the eastern and western portions of Progress Energy's service territory in North and South Carolina (formally known as Carolina Power and Light). Effective July 2, 2012, Progress Energy Inc. merged with Duke Energy Corporation. At the time of this report, CPL and DUK continue to operate as separate balancing authorities even though the two systems are jointly dispatched.
- DUK: Duke Energy Carolinas
- PJM: PJM Interconnection
- SC: South Carolina Public Service Authority (Santee Cooper)
- SCEG: South Carolina Electric & Gas Company
- SOCO: Southern Company
- TVA: Tennessee Valley Authority
- YAD: Yadkin division of Alcoa

Figure 6: Key Paths

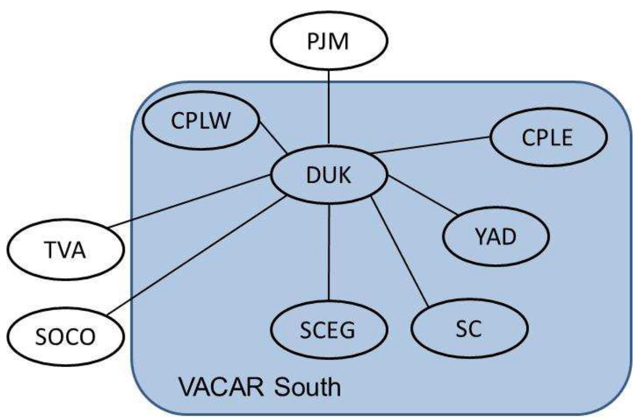
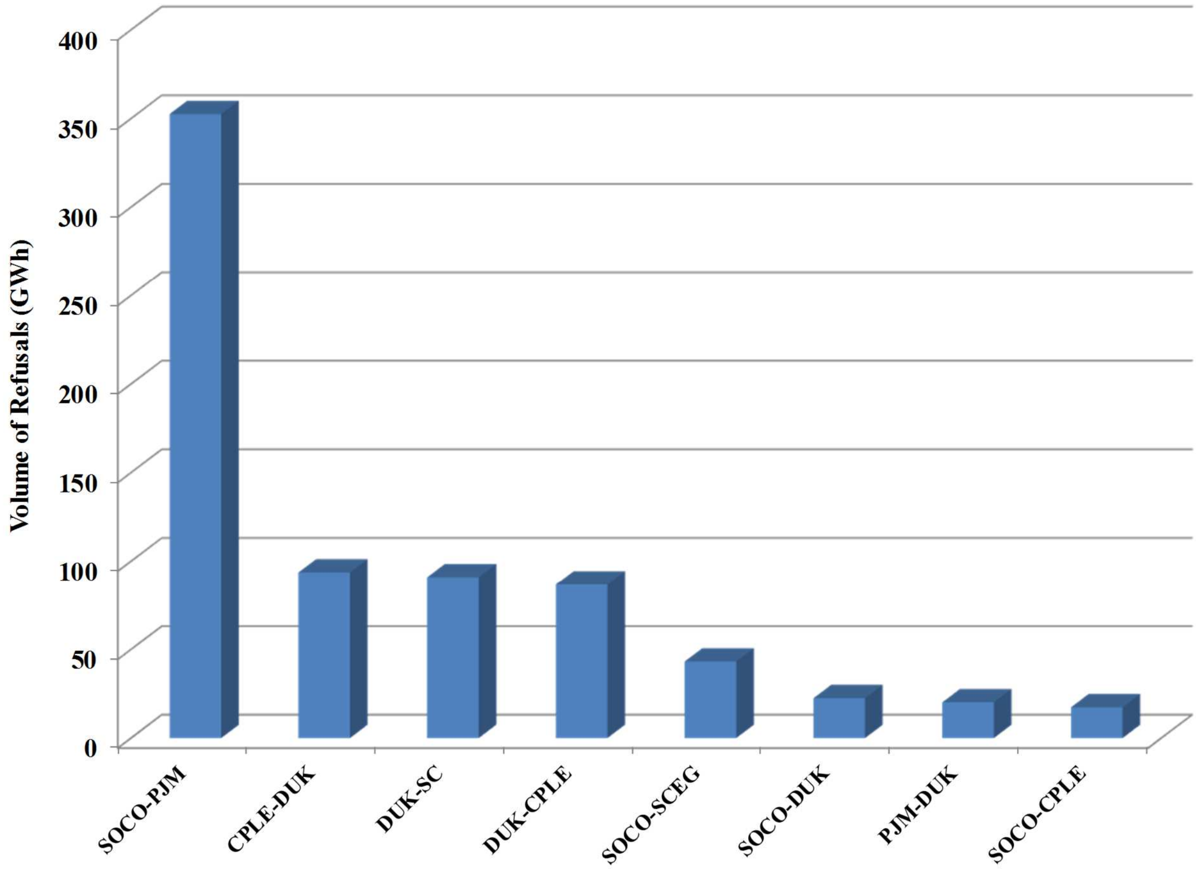


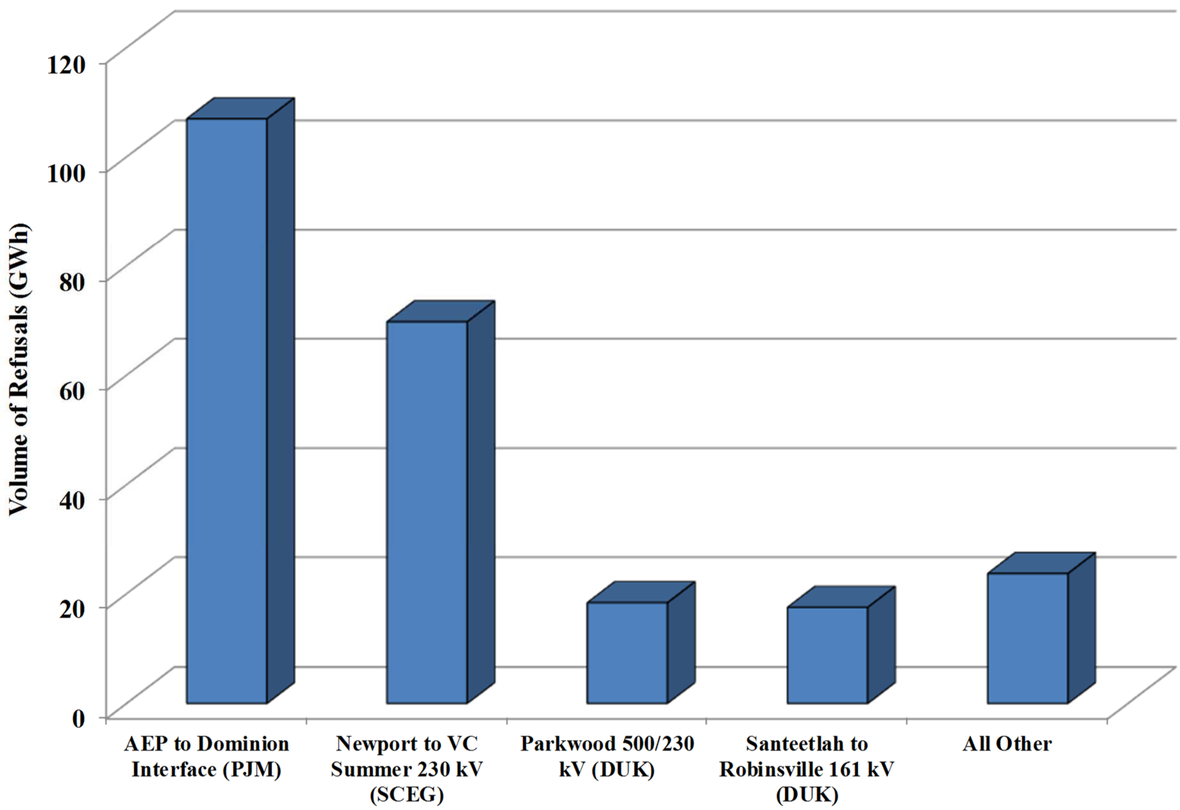
Figure 7 shows the TSR refusals on the eight paths that experienced the most refusals for service during the quarter. The majority of refused service was monthly service that was destined for PJM.

Figure 7: TSR Refusals by Path
January 2018 – March 2018



To analyze the justification of the refusals on these paths, we identified the limiting flowgates behind each TSR refusal and then grouped the flowgates by physical proximity of the monitored elements. An example of proximity groupings would be for flowgates on parallel circuits of the same line. If the first flowgate monitors circuit 1 for the loss of circuit 2, and the second flowgate monitors circuit 2 for the loss of circuit 1, we grouped the two flowgates together for the purpose of our analysis. This grouping is reasonable because the flowgates have the same ratings and the same shift factor or distribution factors from generation operations and transmission outages. We only included the TSRs that were refused during the current quarter. We evaluate the Company's conduct, such as providing the process with reasonable values on flowgate ratings, transmission and generation operations, and committed use. Also, because we evaluated the refusals by reviewing the most recently calculated flows on the flowgates (as described below), we restricted the refusals under review to hourly and daily service increments ("current" TSRs). Reviewing longer term service in this way would not be meaningful because the flow calculations used in the TSR refusals would be from calculations performed well in advance of the service being requested. Flowgate groupings associated with this quarter's TSR refusals for hourly and daily service are listed in Figure 8 below. As noted earlier, TSRs can be refused to maintain contract path limits. Incidences of these refusals are included in the "All Other" category along with refusals that do not specify a limiting flowgate.

Figure 8: Key Flowgates Linked to Current TSR Refusals
January 2018 – March 2018



The flowgate data in Figure 8 is also useful for analyzing Duke's ATC values. Duke's method for calculating ATC is a two-step process. The first step uses a "Model Builder", which is a power-flow model that calculates base flows and Transmission line Distribution Factors ("TDFs") based primarily on the planned generation dispatch and the expected topology of the transmission system. The Model Builder considers generation dispatch to meet network and native load requirements and also accounts for planned transmission and generator outages. The key output is the loading on various transmission flowgates. The second step in the process is the "ATC Calculator", which uses line loadings from the Model Builder output. This calculator adjusts the AFC values to reflect schedules and transmission service requests, as well as contract path limitations in order to determine ATC.[8]

Adjusting AFC to reflect transmission rights being purchased and then scheduled is expected and reasonable. Because we are interested in the impacts of Duke's generation and transmission system operations on transmission access, we reviewed the results of the Model Builder base flows excluding the effects of TSRs and schedules. The flowgate rating less the estimated post-contingent base flow on each flowgate gives a value we call the "Base AFC". Essentially, it is capacity remaining on the flowgate after the anticipated flows on each flowgate from the forecast generation, load, and transmission system topology. If the base AFC is not accurate, it can reduce the posted AFC values. For the top four groups of key flowgates in Figure 8, we analyzed the Base AFC metric. The analyses are presented in Figure 9 through Figure 12.

In each of the figures, the shaded bars indicate days when there were TSR refusals due to lack of AFC on that particular flowgate. For the purposes of these analyses, we only highlight days with hourly or daily refusals. This allows us to isolate any relationship between the daily and hourly refusals and the Base AFC values.

We sought to understand the circumstances when a drop in Base AFC (shown by the solid line) was coincident with a TSR refusal in order to ensure that the refusals were proper and justified. In particular, when the Base AFC decreases, it can lead to a smaller amount of transmission capacity for sale to the market. On days when a Base AFC drop occurred coincident with a TSR refusal, we identified possible causes for the drop, including transmission outages and generation forecasts in the Model Builder.

We include a dotted line labeled "Generation Contribution." This is an estimate of the effect of Duke and Progress generation on the Base AFC. It is the sum of the products of the generation

[8] The procedures used by the AFC Calculator to determine the final ATC are defined in Attachment C of the Duke Tariff. Further detail on Duke's methods for establishing ATC are provided in the document "Duke Energy Carolinas Available Transfer Capability Implementation Document (ATCID)" which is posted on their OASIS site.

shift factors (defined in the counter flow direction) and the real-time generation from Duke and Progress generators. Hence, changes in the Generation Contribution should lead to changes in base AFC values in the same direction. However, Base AFC is also impacted by transmission topology changes, load patterns, and generation changes external to the Duke system. Large Generation Contribution changes are sometimes the results of generation outages. The Model Builder uses forecast dispatch, which will reflect scheduled outages. Immediate unplanned outages may not have been known in time to be included in the Model Builder assumptions. Differences between actual dispatch and planned dispatch can lead to inaccuracies in the AFC process.

The specifics of our analyses vary depending on the owner of each flowgate. When the owner is an entity other than Duke, that entity calculates its own AFC values which supersede the values calculated by Duke.[9] We indicate the flowgate owner as a suffix to the flowgate name. During this study period, there was one key Duke flowgate. For all flowgates, regardless of owner, we normally review Duke transmission outages and generation operations. At the time of this report, the data needed for reviewing transmission outages had not been provided, so this portion of the analysis will be done through a special investigation once the data is received. Study dates are selected from events where downward spikes in Base AFC were coincident with TSR refusals.

For Duke-owned flowgates, we checked for changes in flowgate ratings for and, in certain cases, we verified the accuracy of the modeling results by comparing forecasted flows with the flows observed in real-time operations. More precisely, we first checked to see if these flowgates were logged as having real-time contingency violations on the study dates. If they were, then any value of Base AFC leading to TSR refusals for those days is considered accurate. If the flowgates do not appear in the contingency violation logs on the study dates, then we review real-time flow data. If real-time loadings peak to within approximately ninety percent of the

[9] CPL flowgates are not treated as owned by Duke even though CPL is part of Progress Energy. Although Progress Energy Inc. is now a wholly owned direct subsidiary of Duke Energy Corporation, Progress Energy Inc. and Duke Energy Carolinas, LLC are separate balancing authorities and operate under separate tariffs. The scope of the independent transmission service monitor is to monitor Duke Power which is now known as Duke Energy Carolinas, LLC. Progress Energy Inc. is outside the scope of the current monitoring plan.

limits, we again consider the Base AFCs leading to TSR refusals to be accurate, because actions taken in real-time should unload the flowgates to resolve the violations, leaving the flowgates in this range. Finally, if the flowgates are not loaded near the limits in real time, we calculate the observed peak post-contingent flow over the day from the real-time data. We then compare this to the sum of the Base AFC and the TRM plus the rating. This represents the forecasted post-contingent flow. If this forecasted flow is greater than or similar to the observed flow in real time, then the AFC process is deemed to be accurate from the perspective of not understating transmission capability. We now consider each flowgate separately in the following figures.

Figure 9: Base AFC – AEP to Dominion Interface (PJM)
January 2018 – March 2018

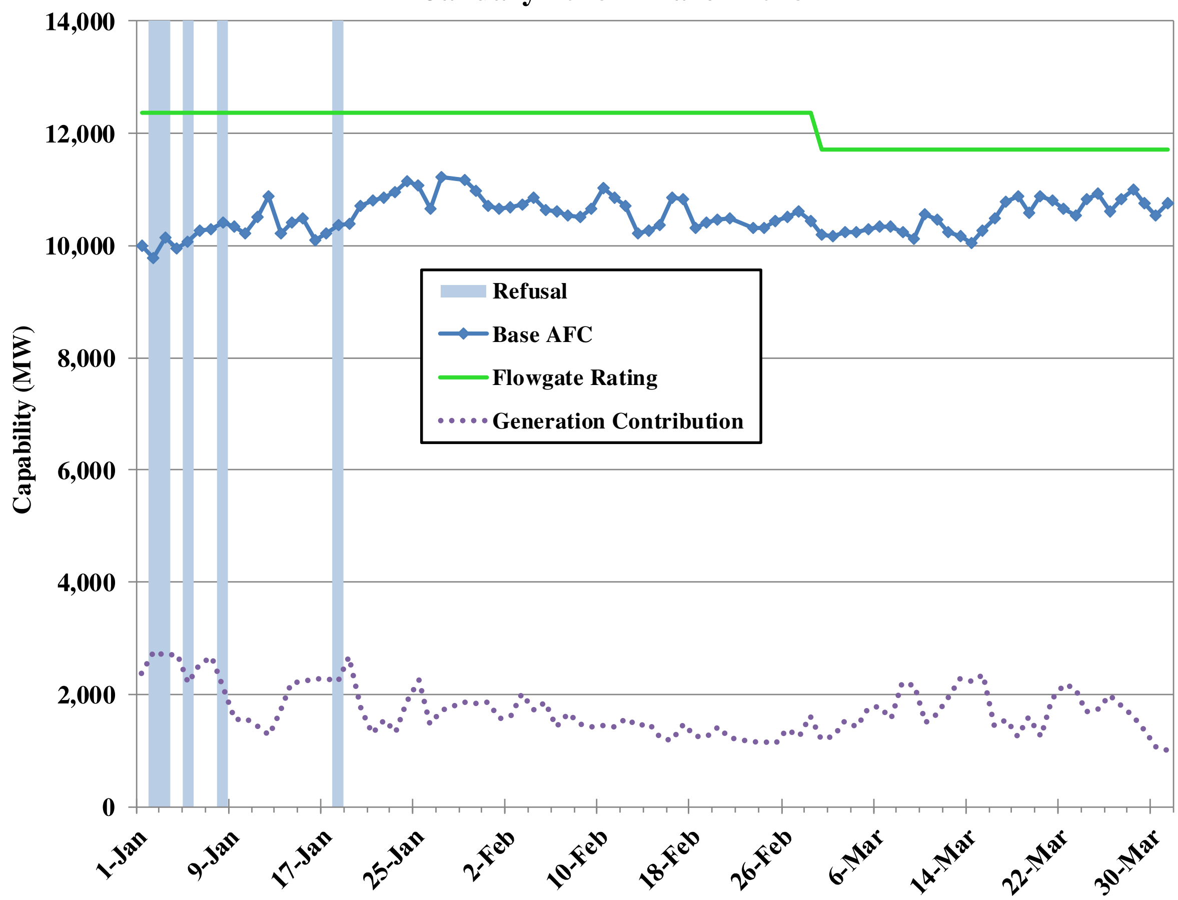


Figure 9 shows the *AEP to Dominion Interface (PJM)* flowgate. It has a contingent element of the Cloverdale 765/345 kV transformer. This flowgate was the cause of twelve hourly, daily or weekly TSR refusals, on a variety of paths.

The rating on this flowgate was [redacted] MW until March 1 when it [redacted].

As can be seen from the dotted line in the figure, Duke and Progress generation has a minimal effect on the flowgate. The Generation Contribution was relatively low at the times of the TSR refusals. The flowgate is configured in the North to South direction, so increased output of Duke generation that is towards the Northwest part of the BA and connected to the 500 kV system has the potential to unload it. The [redacted] have the largest effect with approximately a generation shift factor of -[redacted] percent. No generation in Duke had a positive generation shift factor. Most of the Generation Contribution movement is due to normal pumped storage system cycling. We did not find any generation outages that made a significant contribution to Base AFC reductions, but we evaluate early January generation outages in the Generation Availability section of this report.

Based on our evaluation of this flowgate, we find no anticompetitive conduct.

Figure 10: Base AFC – Newport to VC Summer 230 kV (SCEG)
January 2018 – March 2018

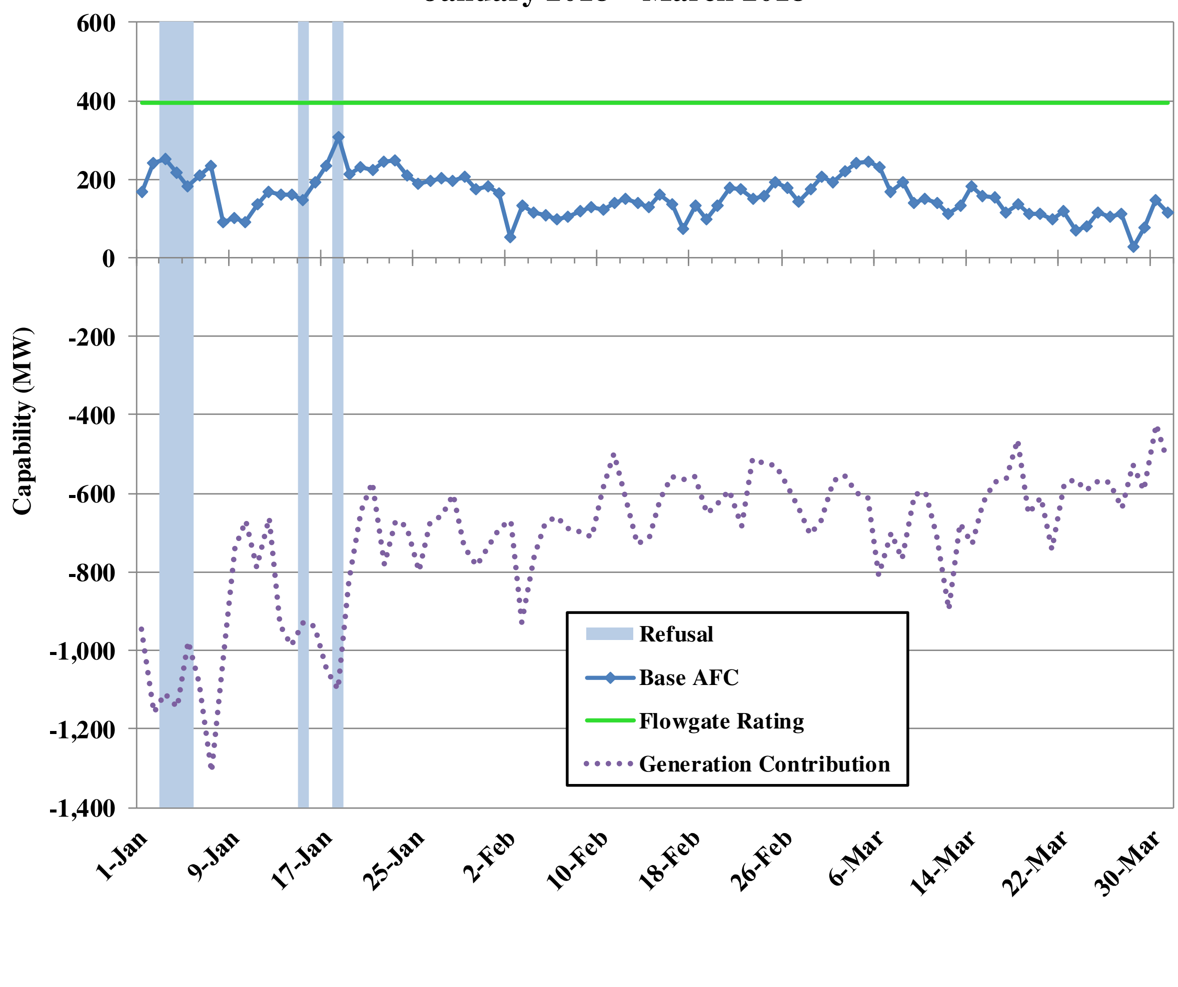


Figure 10 shows the *Newport to VC Summer 230 kV (SCEG)* flowgate. There were eight hourly or daily TSR refusals for this flowgate affecting mostly the DUK to CPLE path.

This flowgate had a rating of [redacted] MW.

The dispatch of Duke generation explains some of variations in base AFC, as shown by the dotted purple line in Figure 10. The Duke generation loads the flowgate with the maximum contribution coming from the [redacted] station, which has a generation shift factor of approximately [redacted] percent. Duke generation outages are not a concern because they would unload the flowgate.

Based on our evaluation of this flowgate, we find no anticompetitive conduct.

Figure 11: Base AFC – Parkwood 500/230 kV (DUK)
January 2018 – March 2018

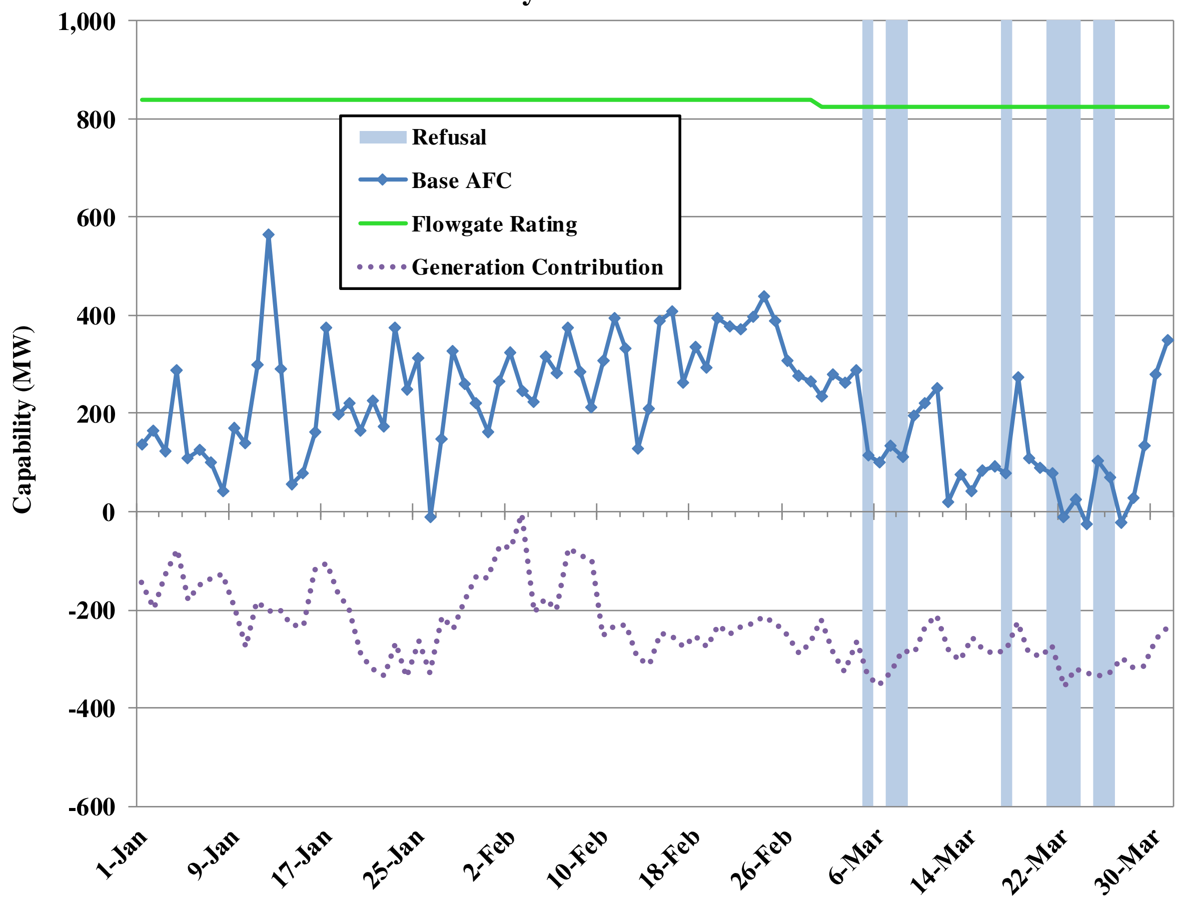


Figure 11 shows the *Parkwood 500/230 kV (DUK)* flowgate. The contingent element for this flowgate is the parallel transformer. The flowgate was the cause of 39 weekly, daily or hourly TSR refusals, mostly on the DUK to CPLE path.

The rating on this flowgate was [redacted] MW until March 1 when [redacted]

The Base AFC on this flowgate is influenced by Duke and Progress generation as can be seen from the dotted purple line in the figure. Duke generation outages are not of concern because no Duke generation unloads this flowgate. The Progress [redacted] and [redacted] stations unload the flowgate with generation shift factors of approximately [redacted] percent. During the TSR refusal events, the only unplanned outage of these [redacted] stations was for [redacted] which was in a [redacted] MW derate from [redacted] due to the [redacted] We find this derate to be justified.

Because this is a Duke flowgate, we reviewed the accuracy of the AFC process by analyzing how close the flow in real time corresponded to the forecasted flows. We reviewed data from three days when the Base AFC values were negative and coincident or nearly coincident with refusals. We found that on all three days, the flowgate reached loadings of 103 percent of the rating. This indicates that the day-ahead studies were an accurate predictor of real-time conditions for this flowgate.

Figure 12: Base AFC – Santeetlah to Robinsville 161 kV (DUK)
January 2018 – March 2018

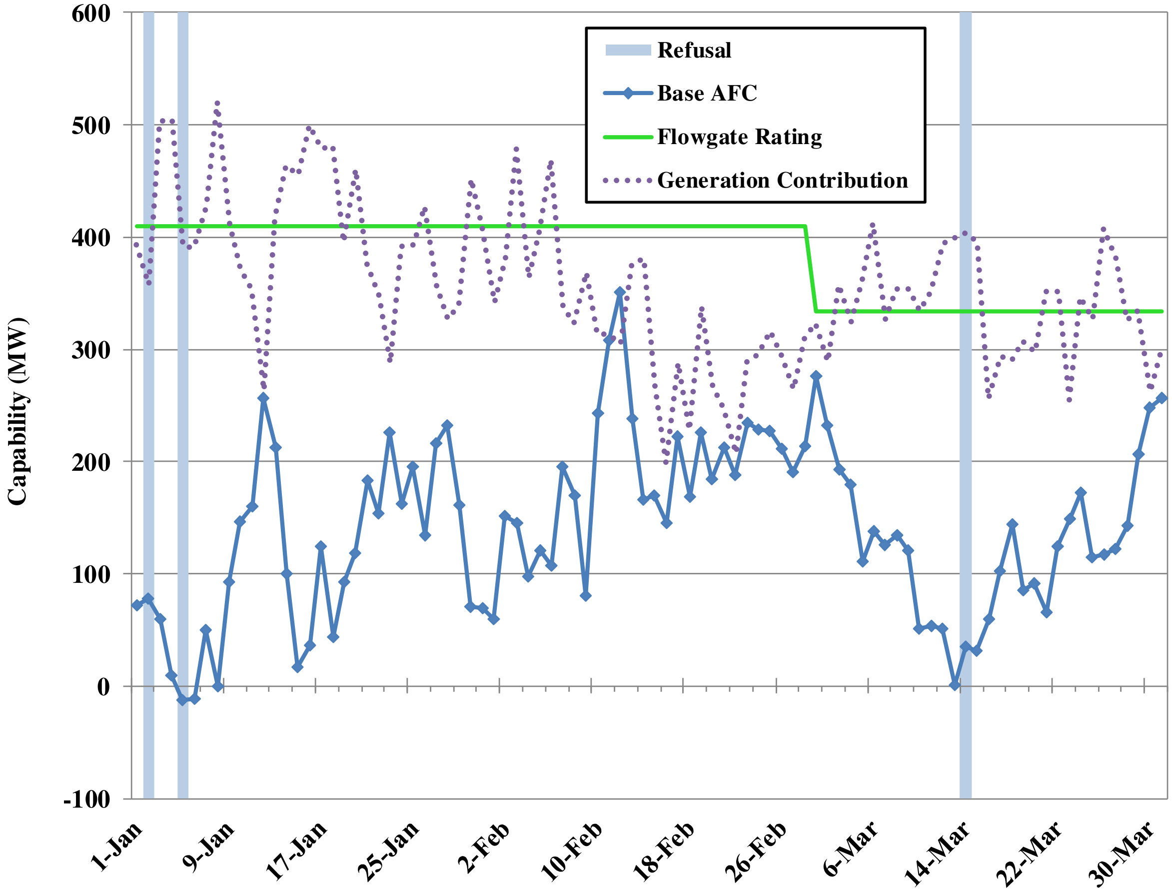


Figure 12 shows the *Santeetlah to Robinsville 161 kV (DUK)* flowgate. This flowgate has the *Nantahala to Fontana 161 kV (TVA)* line as its contingent element and was the cause of six hourly or daily refusals, mostly on the *TVA to DUK* path.

The rating on this flowgate was [redacted] MW until March 1 when [redacted].

The Base AFC on this flowgate is not correlated with Duke and Progress generation as can be seen from the dotted purple line in the figure. Essentially, all Duke and Progress generation unload this flowgate with a generation shift factor of approximately -[redacted] percent. Most of the Generation Contribution movement is due to normal pumped storage system cycling. We did not find any unplanned Duke generation outages that significantly impacted this flowgate during the times of TSR refusals.

Because this is a Duke flowgate, we reviewed the accuracy of the AFC process by analyzing how close the flow in real time corresponded to the forecasted flows. We reviewed data from five days when the Base AFC values were low or negative and coincident or nearly coincident with refusals. We found that when the Base AFC was near zero or negative, the flowgate was at or exceeding the limit in real-time. When the Base AFC was positive, the forecasted flows were moderately less than the real-time flows. This supports the conclusion that the AFC process is accurate and not unjustifiably limiting access to transmission service.

Based on our evaluation of this flowgate, we find no anticompetitive conduct.

V. Monitoring for Anticompetitive Conduct

In this section, we report on our monitoring for anticompetitive conduct. The market monitoring plan calls for identifying anticompetitive conduct, which includes conduct associated with the operation of either Duke's transmission assets or its generation assets that can create transmission congestion or erect barriers to rival suppliers, thereby raising electricity prices. To identify potential concerns, we analyze Duke's wholesale sales in the first subsection below, its dispatch of generation assets in the second subsection, and Duke's transmission operations in the third subsection.

A. Wholesale Sales and Purchases

We examined transaction data to determine whether the prices at which Duke sold or purchased power may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in congested periods. If Duke were engaging in anticompetitive conduct to create congestion, it could potentially benefit by making sales at higher prices in constrained areas or purchases at lower prices adjacent to constrained areas. We examined the real-time bilateral transactions made by Duke using Duke's internal records. We focus on real-time transactions because anticompetitive conduct is likely to be more successful in the real-time market.

Competition is facilitated by the ability of rivals to gain market access by reserving and scheduling transmission service. Access will be limited if ATC is unavailable, transmission requests are refused, or schedules are curtailed. Curtailments are also an indicator of congestion because they can be made when a path is over-scheduled or physically overloaded. If Duke's ability to curtail schedules is being abused, we would expect to see systematically higher prices for sales or lower prices for purchases coincident with curtailments. Many of the curtailments are caused by TLRs.

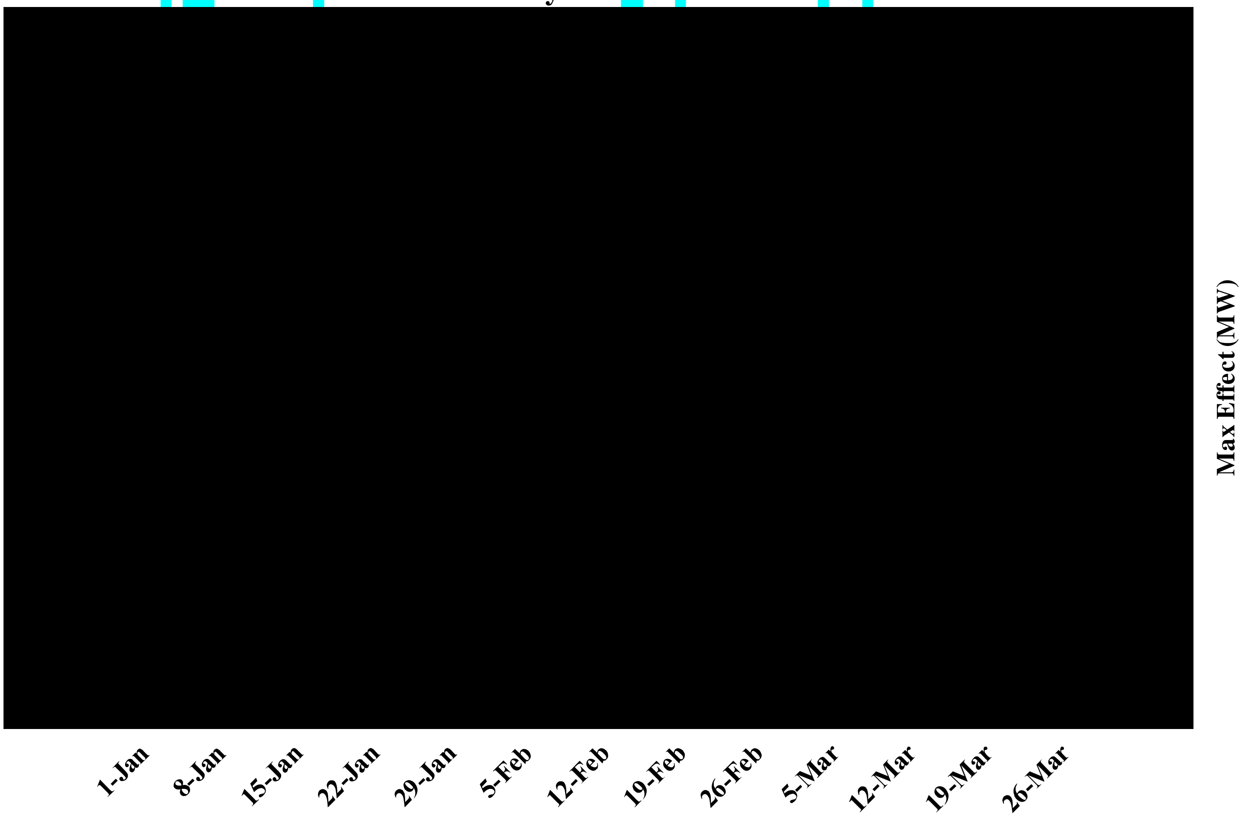
Curtailments can be flow-based (i.e., the result of flows exceeding the system operating limit), or non-flow-based. For our analysis of Duke's sales, we use both types of curtailments. This is reasonable because both types of curtailments reduce market access. Moreover, Duke has the direct ability to affect both flow-based curtailments and non-flow-based curtailments. It can affect flow-based curtailments through operating activities and it can affect non-flow-based curtailments by unjustifiable schedule reductions. By analyzing the relationship of curtailment data to sales activities, we can focus attention on events that merit further inquiry. In particular, we monitor any link between curtailments and Duke's position in the real-time markets that could have potentially benefited from the curtailments. To monitor this, we calculate a measurement called the maximum daily effective market position ("Max Effect"). The Max Effect indicates Duke's trade volume that could have potentially benefited from a particular curtailment. Days with curtailments coincident with high Max Effect levels are days when the curtailments could have potentially allowed Duke to exploit the effect of the curtailment. These days are further evaluated to determine if the transactions were done at pricing levels that are consistent with a pattern of anticompetitive conduct.

The Max Effect is calculated in three steps. First, for each hour, constraint, and delivery point, we calculate a shift-factor-weighted[10] volume of trades by finding the product of the shift factors and the net trade volumes (purchases minus sales). Second, for each hour and each constraint, the products values from the first step are summed across all delivery points. Third, from this set of values, we select the maximum value for each day from the hour and constraint combinations. If the maximum value is positive, we evaluate it more closely.

Figure 13 shows the daily average prices received by Duke for real-time sales and purchases. The blue shading indicates days when curtailments occurred that were potentially beneficial to Duke's positions in the real-time markets as indicated by a positive Max Effect.

[10] The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path. Shift factors between -.01 and .01 are set to zero.

Figure 13: Prices for Duke Sales and Purchases
January 2018 – March 2018



The figure shows the weighted average sales and purchase prices for each day that transactions occurred. There were [redacted] days with tag curtailments that had a positive Max Effect. The weighted average daily price of Duke's sales ranged between $[redacted] and $[redacted] and averaged $[redacted] per MWh during the quarter. The weighted average daily prices of Duke's purchases range between $[redacted] and $[redacted] per MWh and averaged $[redacted] per MWh. On the days with potentially beneficial tag curtailments, weighted average daily price of Duke's sales ranged between $[redacted] and $[redacted] and averaged $[redacted] per MWh during the quarter. The weighted average daily prices of Duke's purchases range between $[redacted] and $[redacted] per MWh and averaged $[redacted] per MWh. On average, Duke was selling and purchasing at higher prices during congestion. We looked further at [redacted] due to a high Max Effect (greater than 50 MW) coincident with relatively low-cost purchases or high-cost sales. These were the three days with potentially beneficial tag curtailment, defined as periods when either purchase prices were lower than neighboring days or sales prices were higher than neighboring days.

- [redacted] was selected for high price sales, but there was no sales volume during the time of day with the potentially beneficial tag curtailments. This Max Effect is driven by purchases but the purchase price was higher than normal so these were not beneficial.
- [redacted]hour ending [redacted] Duke was purchasing [redacted] MW of power from [redacted] for $[redacted] per MWh while an e-tag from [redacted] was curtailed due to a TLR. This day was flagged due to a weighted average purchase price of $[redacted] per MWh, which was low compared to neighboring days. However, the sales contributing to the low average occurred on hours when there was not a Tag Curtailment. This purchase is not a cause for concern because it does not stand out as a "low-cost" purchase.
- On [redacted] ending [redacted] Duke was purchasing [redacted] MW of power from [redacted] for $[redacted] per MWh while an e-tag from [redacted] was curtailed due to unit issues. This purchase is not a cause for concern because the unit causing the curtailment was not in the Duke area and Duke did not initiate the curtailment.

We do not find dates from the Sales and Purchases analysis that warrant special attention.

B. Generation Dispatch and Availability

We examined the company's generation dispatch to determine the extent to which congestion may have been the result of uneconomic dispatch of generation by Duke. We conducted two analyses. We first determined the hourly quantities of out-of-merit dispatch and the degree to which the out-of-merit dispatch contributed to flows on congested transmission paths. If the contribution is significant, further investigation of these times may be warranted. We use flow-based curtailments because these types of curtailments (as opposed to contract-path-based curtailments) are the ones that would result from unjustified out-of-merit dispatch. Second, we examine the "output gap", which measures the degree to which Duke's generation resources were not fully scheduled when prevailing prices exceeded the marginal cost of running the unit.

Effective July 2, 2012, as part of the merger between Duke and Progress Energy, Duke has been performing a joint dispatch of their generation units and Progress Energies generation units. Because of this, we include both sets of units in our analysis of generation dispatch. We refer to the combined set of units as "Duke's units". However, we do not include the Progress units in the analysis of generation availability.

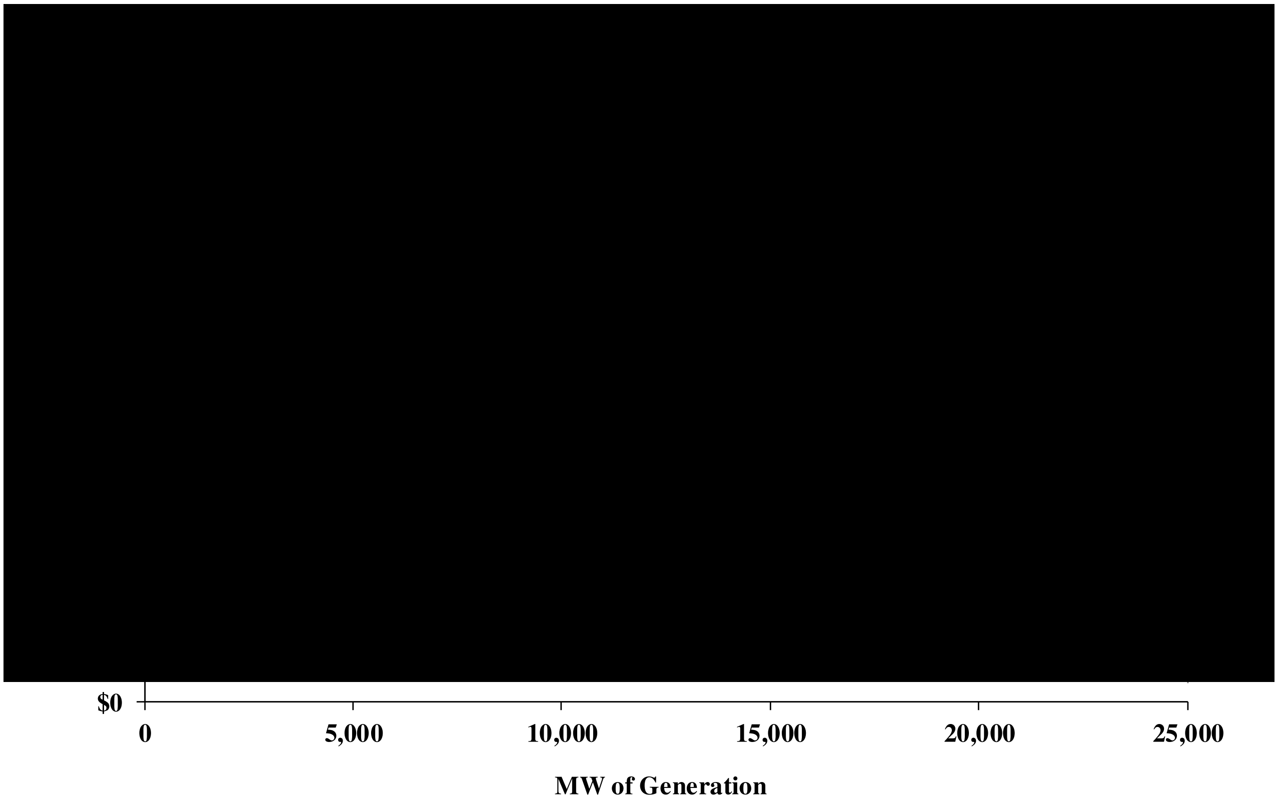
1. Out-of-Merit Dispatch and Curtailments

Congestion can be a result of limits on the transmission network when utilities dispatch their units in a least-cost manner. This kind of congestion does not raise competitive concerns. If, alternatively, a departure from least-cost dispatch ("out-of-merit" dispatch) is unjustifiable and causes congestion, it does raise potential competitive concerns.

We pursue this question by measuring the out-of-merit dispatch on the Duke system. In our analysis, we consider a unit to be out-of-merit when it is dispatched in favor of a lower-cost unit that is not fully loaded. To identify out-of-merit dispatch, we first estimate Duke's marginal cost curve or "supply curve".[11] We use incremental heat rate curves, fuel cost and other variable operations and maintenance cost data provided by Duke to estimate marginal costs. This allows us to calculate marginal costs for Duke's units. We order the marginal cost segments for each of the units from lowest cost to highest cost to represent the cost of meeting various levels of demand in a least-cost manner. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages and planned deratings.

[11] We use the term marginal cost loosely in this context. The value we calculate is actually the *marginal running cost* and does not include opportunity costs, which may include factors such as outage risks or lost sales in other markets.

Figure 14: Duke and Progress Energy Supply Curve



Note: The figure excludes nuclear and hydro capacity.

Figure 14 shows the estimated supply curve for a representative day during the period of study. The dispatch analysis excludes nuclear and hydro units because their operation is not primarily driven by current system marginal operating costs. Nuclear resources rarely change output levels and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

As the figure shows, the marginal cost of supply increased as more units were required to meet demand. The highest marginal cost was $[redacted] per MWh. We used each day's estimated marginal cost curve as the basis for estimating Duke's least-cost dispatch for each hour in the study period.

In general, this method will not be completely accurate because we do not consider all operating constraints that may require Duke to depart from our estimate of least-cost dispatch. In particular, this analysis does not model generator commitments, assuming instead that all available generators are online. Consistent with this assumption, we limit the hours in this analysis to include only those between the morning ramp and the evening ramp in order to avoid the distortions caused by generation commitments and de-commitments. While the analysis could be expanded to refine the estimated generator commitment and dispatch to make it correspond more closely to actual operating parameters (i.e., start costs, run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

Other justifiable operating factors that cause the out-of-merit dispatch to be overstated include energy limitations and ancillary services. An example of an energy limitation is a coal delivery problem that prevents a coal plant from being fully utilized. Because the coal plant is still capable of operating at full load for a shorter time period, the condition does not result in a planned outage or derating. The necessity to operate the plant at reduced load to conserve coal can cause the out-of-merit values to be overstated.

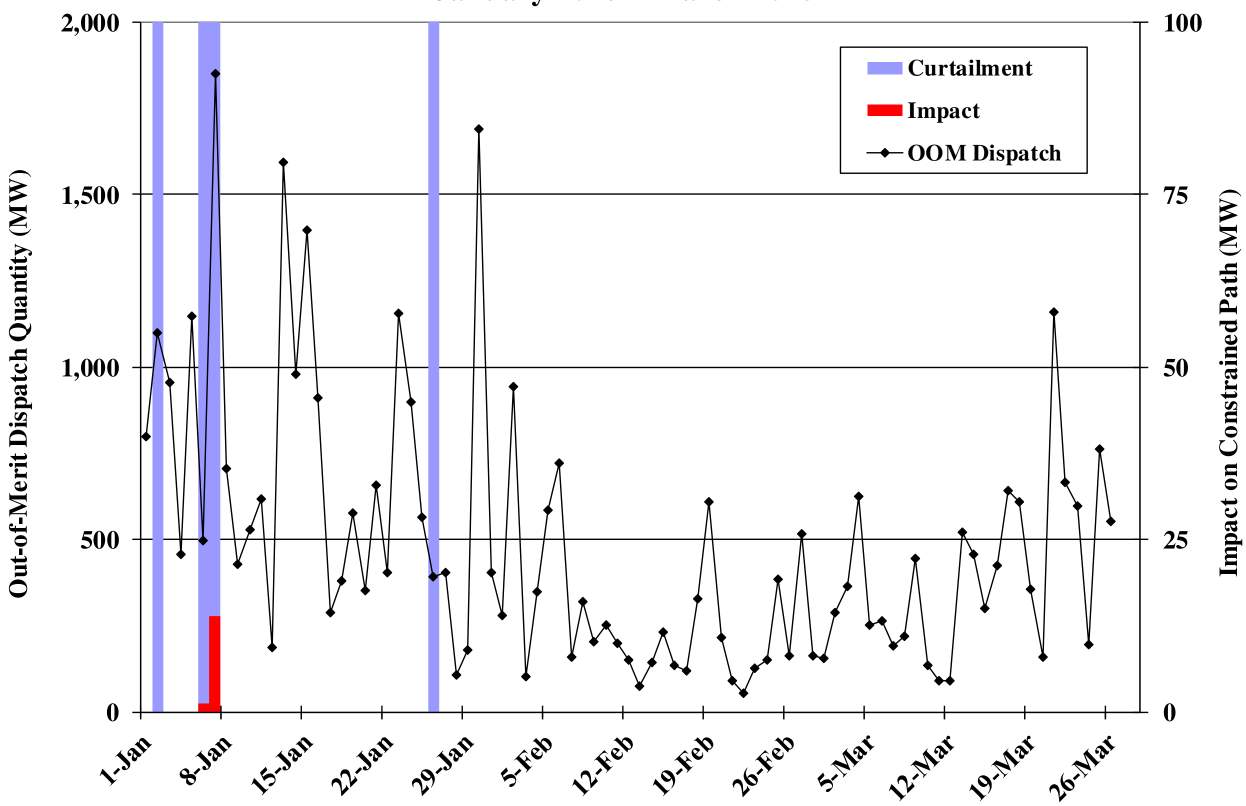
Ancillary services requirements such as spinning reserves, system ramp rate limitations, and Automatic Generation Control (AGC) requirements can make it operationally necessary to dispatch several units at partial load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated. The out-of-merit quantities include units on unplanned outage since a sudden unplanned outage may be an attempt to uneconomically withhold generation from the market.

Although our analysis will tend to overstate the quantity of generation that is truly out-of-merit, the accuracy of a single instance of out-of-merit dispatch is not as important as the trend or any substantial departure from the typical levels.

In our analysis, we seek to identify days with significant out-of-merit dispatch that coincides with transmission congestion. Congestion is indicated by flow-based schedule curtailments. Flow-based curtailments are those that are taken close to real-time in order to prevent physical flows from exceeding system operating limits. Out-of-merit dispatch can be used to affect these flows and create the need for curtailments, potentially limiting competition in specific locations. Conversely, contract-path-based curtailments are not included because they are the result of reserved rights on the contract paths and are unaffected by real-time dispatch.

Figure 15 shows the daily maximum "out-of-merit" dispatch for the peak hours of each day in the study period, unless there is positive impact. For days with positive impact, the figure shows the impact for the peak hour with the maximum impact and the "out-of-merit" dispatch corresponding to that hour.

Figure 15: Out-of-Merit Dispatch and Congestion Events
January 2018 – March 2018



The figure shows one day, January 7, with flow-based curtailments (represented by the blue bar) that had impact over two MWs. We reviewed the circumstances and found that the prolonged extreme cold conditions and resulting high peak loads [redacted]

[redacted] Based on this, we find the dispatch pattern on this day to be reasonable and justified.

2. Output Gap

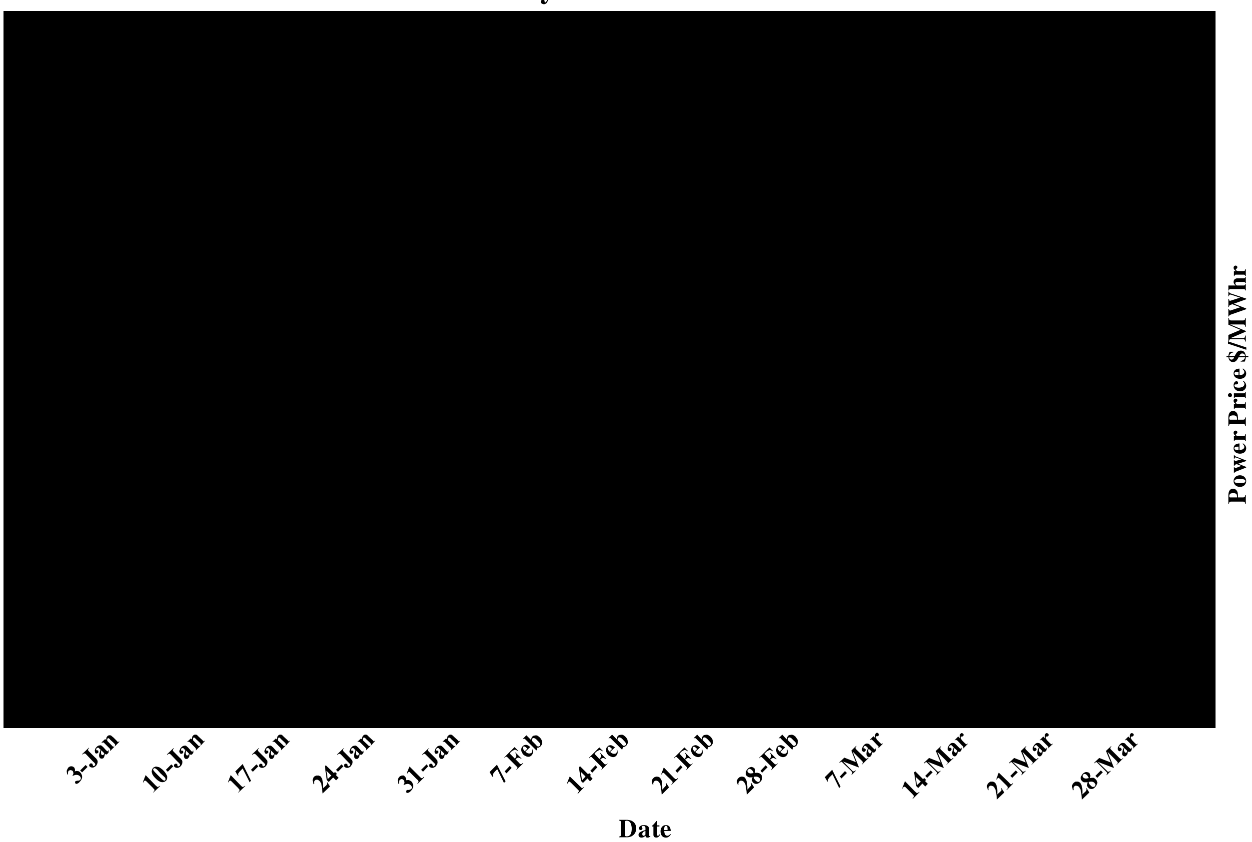
The output gap is another metric we use to evaluate Duke's generation dispatch. The output gap is the unloaded economic capacity of an available generation resource. The capacity is economic when the prevailing market price exceeds the marginal cost of producing from that unit by more than a specified threshold. We use $25 and $50 per MWh as two thresholds in our analysis. Hence, at the $25 per MWh threshold, if the prevailing market price is $60 per MWh and a unit with marginal costs of $40 per MWh is unloaded, then we do not consider this part of the output gap because the marginal cost plus the $25 per MWh threshold is greater than the $60 per MWh market price. However, if the marginal cost is $30 per MWh, we would consider it in the output gap at the $25 per MWh threshold, but not under the $50 per MWh threshold.

We analyze the market for the 16-hour daily on-peak power product because this is the most liquid market in the region and it is where market power would be the most profitable. We also analyze the 16-hour on-peak average of the hourly PJM real-time market prices because it is the most liquid real-time market in the region. We compare these prices to the marginal cost of each generator. The daily output gap for each generator is expressed as the minimum hourly output gap level for each category over the course of the day. The results are the sum of the daily output gap of the included generation. Only units that are committed during the day are included in the daily calculation. Hydro and nuclear units are also excluded because nuclear resources rarely change output levels in response to market conditions for a variety of reasons and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

For this analysis, we define the market price as the minimum between the wholesale power index price and PJM real-time prices at the AEP hub. We chose this composite price to ensure that, if a portion of a unit's capacity were included in the output gap, both day-ahead and real-time prices were taken into consideration. Theoretically, dispatch should be driven by real-time prices, but the timing of natural gas nominations and the limited liquidity in the real-time markets cause the day-ahead market to also be important for dispatch. The minimum daily output gap is used in the analysis, because this represents the quantity of power that could have been sold profitably on a sixteen-hour on-peak block schedule without having to commit additional units.

As stated above, we analyze two sources of data that may be representative of prevailing power prices; the wholesale power index price and the PJM market prices. The minimum of these two prices is used as a “composite” price for the $25 threshold. If a threshold is exceeded using the composite price, it is exceeded for both the wholesale power index price and the PJM market price.

Figure 16: Output Gap
January 2018 – March 2018



During the first quarter of 2018, there was one output gap event at the composite threshold on [redacted] one at the PJM market $50 threshold also on [redacted] and five other days with output gap events at the PJM market $25 thresholds. There were four output gap events greater than five MW. These were all at the PJM market $25 threshold and occurred on [redacted]

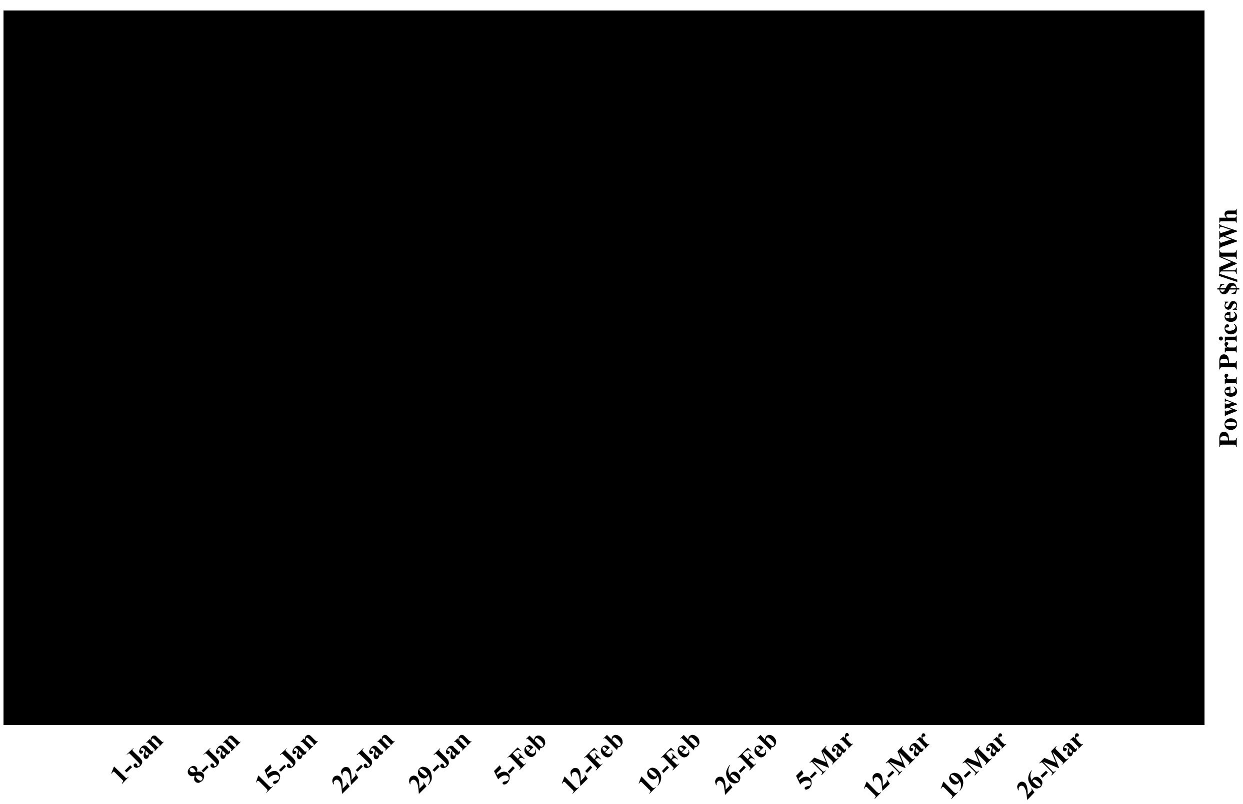
- On [redacted] was operated at reduced load to manage [redacted]
- On [redacted] had returned from an outage the prior day and was at limited output while [redacted] being restored to specification.

Our review of these output gap indications found the dispatch to be reasonable and justified.

3. Generator Availability

We evaluate generator availability by examining the amount of capacity on outage as well as the ratio of capacity on outage to total capacity. Our first analysis is shown in Figure 17. We compare the daily average capacity of Duke resources (excluding Progress resources) on outage during the on-peak hours as well as the wholesale power index price and the prices at which Duke made real-time sales.

Figure 17: Outage Quantities
January 2018 – March 2018



Our primary interest is in unplanned generation outages that cause increases in market prices or Duke purchase prices. We reviewed the data for increases in forced outages coincident with increases in market prices and found potential concerns on January 9, and March 27 through March 31. This includes the dates noted in the wholesale electricity price section of this report. We reviewed these days and found the following:

- The [redacted] MW [redacted] Unit [redacted] went into a two-day unscheduled outage starting on [redacted] to repair a [redacted]
- The [redacted] MW [redacted] went into a two-day unscheduled outage starting on [redacted]
- The [redacted] MW [redacted] Unit [redacted] went into a two-day unscheduled outage starting on [redacted] to repair [redacted]
- The [redacted] MW [redacted] Unit [redacted] went into a three-day unscheduled outage starting on [redacted] to repair a tube leak in the low pressure reheater.

Our review of these generation outages found no evidence suggesting that they were unjustified.

In some cases, the correlation between outages and prices is not immediately apparent. Therefore, we present statistics in Figure 18 to help clarify the relationship. The figure shows the average ratio of capacity in outage to total capacity (i.e., the average outage rate), the wholesale power index price and the Duke short-term sales price. This figure reveals patterns similar to Figure 17. The average planned outage rate started very low and increased to almost fifteen percent in the last days of the quarter. This pattern is consistent with the expected seasonal pattern of planned outages. The average unplanned outage rate during the first quarter was less than one percent.

Figure 18: Outage Rate
January 2018 – March 2018

[redacted]

Power Prices $/MWh

1-Jan 8-Jan 15-Jan 22-Jan 29-Jan 5-Feb 12-Feb 19-Feb 26-Feb 5-Mar 12-Mar 19-Mar 26-Mar

The correlations of the average outage rates to the VACAR price and the short-term sales price are shown in Figure 19.

Figure 19: Correlation of Average Outage Rates with Wholesale Energy Prices
January 2018 – March 2018

	Correlation with Wholesale Price Index	Correlation with Duke Real-Time Sales Prices
Planned Outages	-5%	-67%
Unplanned Outages	26%	55%

Figure 19 shows both planned and unplanned outages. Planned outages are generally scheduled for off-peak periods when prices are normally lowest. Unplanned outages are the most important outages from a market power perspective. The figure shows that there was low correlation between the unplanned outage rate and the wholesale power index. The correlation of unplanned outages with the Duke real-time sales prices was low. Fundamentally, a supply reduction should have upward pressure on prices. Therefore, we do not find evidence of anticompetitive conduct.

C. Analysis of Transmission Availability

Transmission outages are reviewed in order to determine whether they limit market access and, if so, whether the outages are justified. At the time of this report, the data needed had not been provided, so this portion of the analysis will be done through a special investigation once the data is received.