QUARTERLY INDEPENDENT MONITORING REPORT
ON
DUKE ENERGY CAROLINAS, LLC

First Quarter 2015

Issued by:

POTOMAC ECONOMICS

Independent Market Monitor

April 30, 2015

CONFIDENTIAL MATERIAL REDACTED

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I. Overview

This transmission monitoring report evaluates the period from January through March 2015 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" 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 Independent Entity ("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 2015. [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

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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 2015.

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 $28 and $150 per MWh and were strongly correlated with load patterns and natural gas prices. There was a spike in power prices on February 19 and 20. Therefore those days are identified as days of interest and were further evaluated.

Sales and Purchases. Duke engages in wholesale purchases and sales of power on both a short-term and long-term basis. Duke's [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 schedule curtailments or TLRs initiated by Duke. There were 40 TLR events in the region

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.

initiated by other transmission operators and 571 curtailments not associated with TLRs. As discussed herein, we find no unjustified actions by Duke that caused the need for the curtailments.

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 accepted requests during this study period was higher than in the first quarter of 2014 and the approval rate was also high, averaging 97 percent. Given the high volume of service sold and the low level of refusals, 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 "Vogtle to SRS" 230 kV flowgate. We performed a comparison of the 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 to be reasonably accurate. We do not find that accuracy of the process indicates anticompetitive conduct.

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 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. Daily average transaction prices ranged from $[redacted] to $[redacted] per MWh, and there were [redacted] days when Duke's net sales position could have potentially benefited from congestion. We analyzed these days further and found no evidence of anticompetitive conduct.

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 into these events did not find that the out-of-merit dispatch of generation 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. We evaluated Duke's transmission outage events in order to determine whether these events may have unduly impacted market outcomes during the study period. In this evaluation we found no evidence of anticompetitive conduct.

5. Conclusions

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

C. Complaints and Special Investigations

No complaints were filed and no special investigations were initiated this quarter.

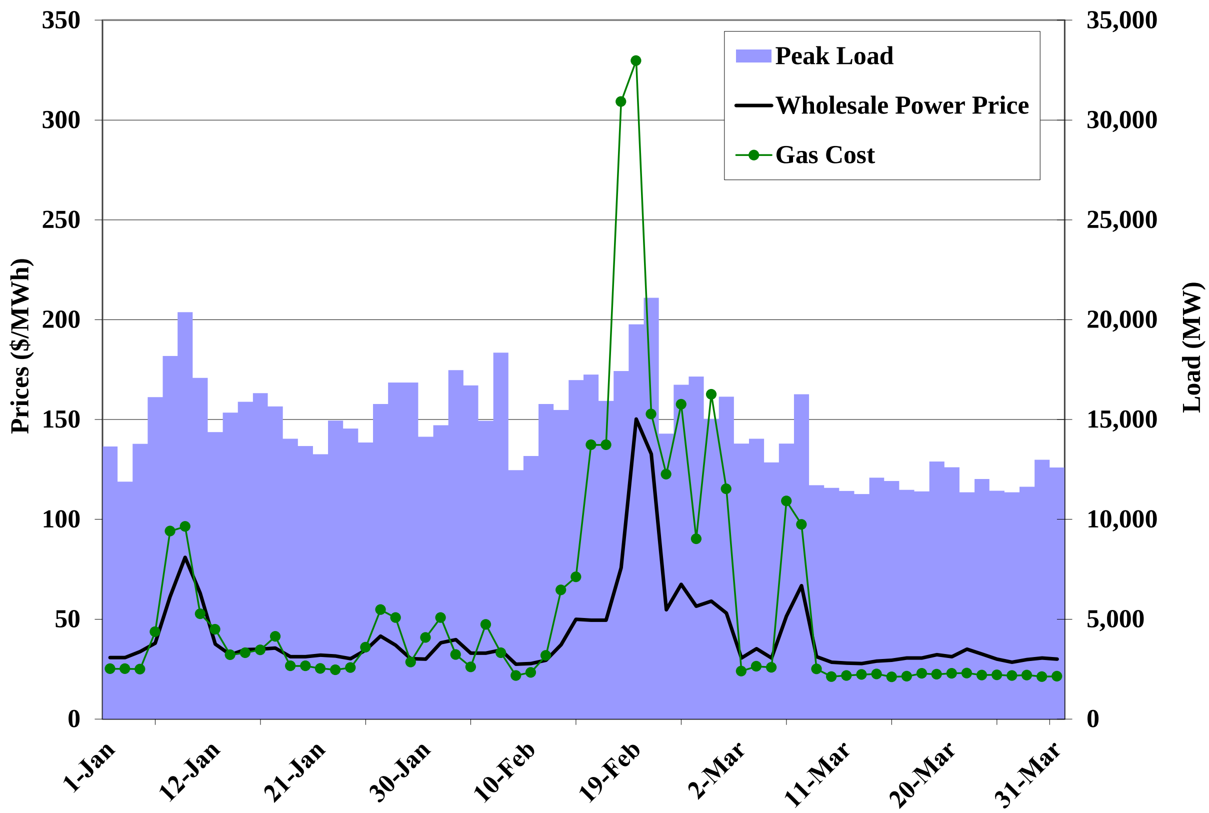
II. Wholesale Prices and Transactions

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 Platts, which we relied upon for this report. Platts publishes prices at various pricing points, including the VACAR (Virginia, Carolinas) sub-region of the South East Reliability Council (SERC), which includes Duke's control area. Figure 1 shows the bilateral contract prices for VACAR along with other market indicators.

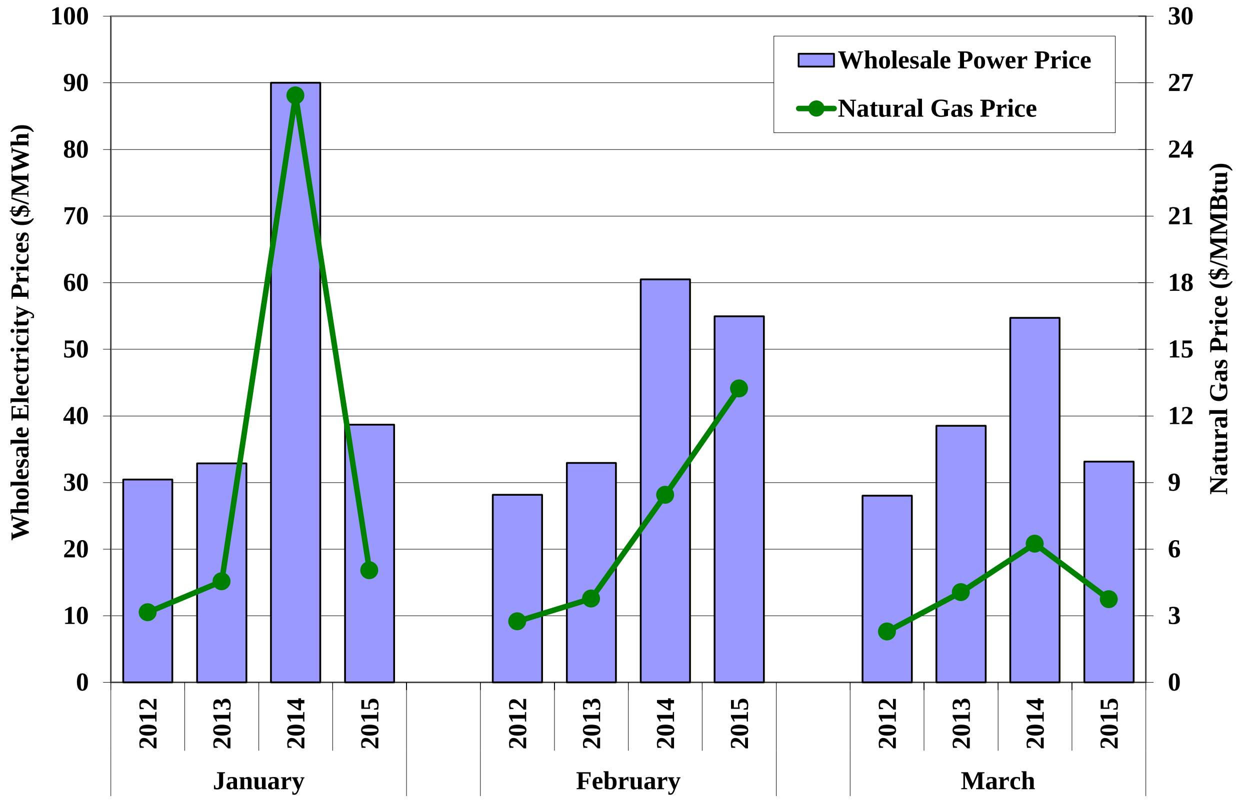
Figure 1: Wholesale Power Prices, Peak Load, and Natural Gas Costs
January 2015 – March 2015



We show system load data because of its positive correlation with power prices. We show natural gas costs because natural gas-fired units are 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 $28 to $150 per MWh over the study period and were strongly correlated with load patterns and natural gas prices. As the figure shows, there was a price spike on February 19 and 20. Otherwise, loads declined towards the end of the quarter and natural gas prices stabilized by mid-March. The next analysis compares the average VACAR 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, 2012 – 2015



As the figure shows, power prices have generally been correlated with natural gas prices over time as one would expect. Power prices show a decrease from 2014 levels for each month, and natural gas prices decreased for January and March 2014 but increased in February 2014. The volatility of natural gas and electricity prices in January and February of 2014 and 2015 can be explained by weather. Both the winter of 2014 and 2015 had events of volatility associated with cold temperatures. In 2014, the extreme cold weather occurred in January and continued episodically in February and March. In 2015 the events were generally in February. Overall, our evaluation of wholesale electricity prices in the Duke region identifies February 19 and 20 as days of interest given the price spikes. Those days will be analyzed further below.

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 2015 – March 2015

[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. At a broad level, the fact that [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.

4 See Transmission Service Monitoring Plan, Section 1.2.

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 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.

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.

During the period of study, there were [redacted] TLRs in the region resulting in the curtailment of 860 schedules that used Duke's transmission service. Duke did not initiate any of these TLRs.

There were also 571 non-TLR curtailments, none of which were initiated by Duke. These curtailments were initiated for various reasons including lack of generation, interface scheduling, PJM ramp limits, and real-time reliability. There was an unusual increase in curtailments by SOCO. They curtailed about 500 schedules in late March. We have no reason to suspect that these SOCO curtailments were influenced by Duke.

Even though Duke did not initiate these 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. These "flow-based" curtailments do not include those associated with minimum generation events because Duke's generation or transmission assets do not significantly contribute to PJM minimum generation events. We would not view the extra SOCO curtailments as flow-based unless a TLR is specified.

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 2014 – March 2015

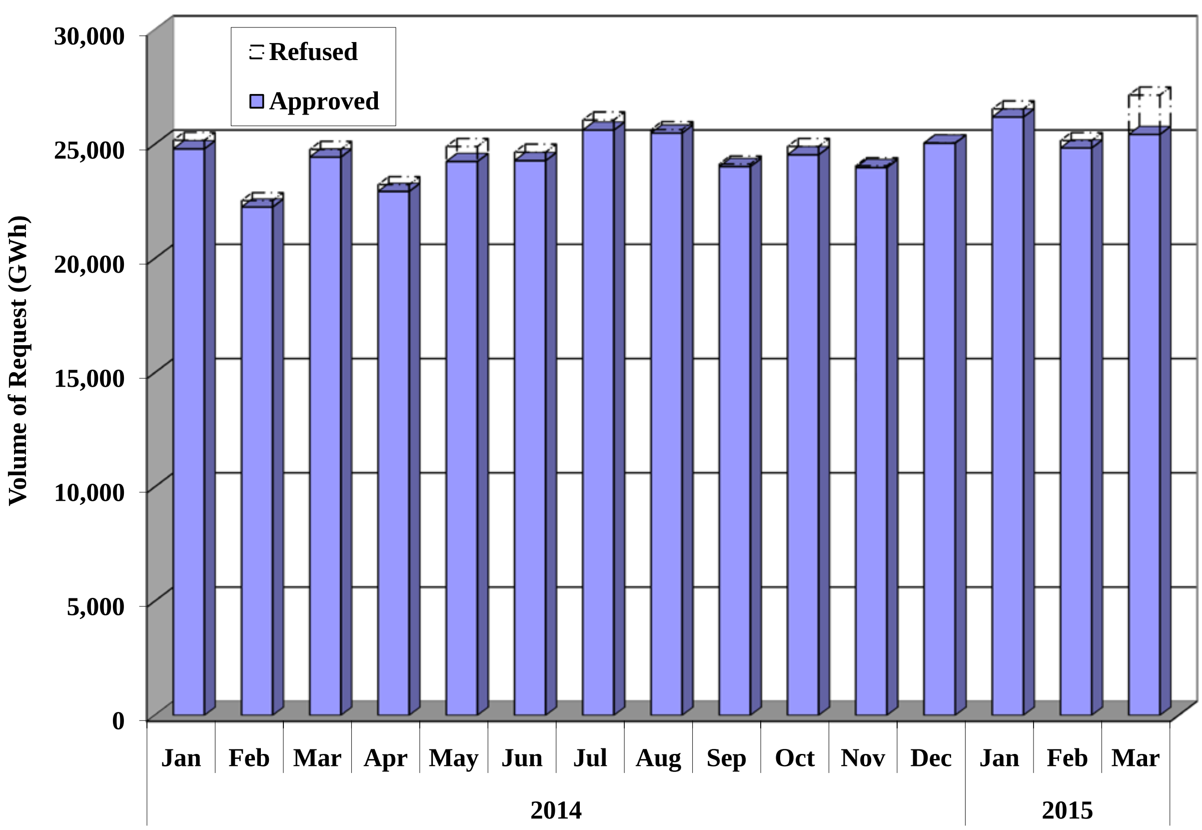


Figure 4 shows the breakdown of transmission service requests in each month from January 2014 through March 2015 and summarizes the disposition of the requests.

The total volume of approved requests during the study period was 76,437 GWh, which was approximately four percent greater than the prior quarter and approximately seven percent greater than the first quarter of 2014. The total volume of refused requests during the study period was 2,409 GWh, which was five times the prior quarter and more than double the first quarter of 2014. The approval rate of transmission service requests was 97 percent for the study period, down from 99 percent in the prior quarter the first quarter of 2014. Given the higher volume of approved requests and the low volume 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, 2014 – 2015

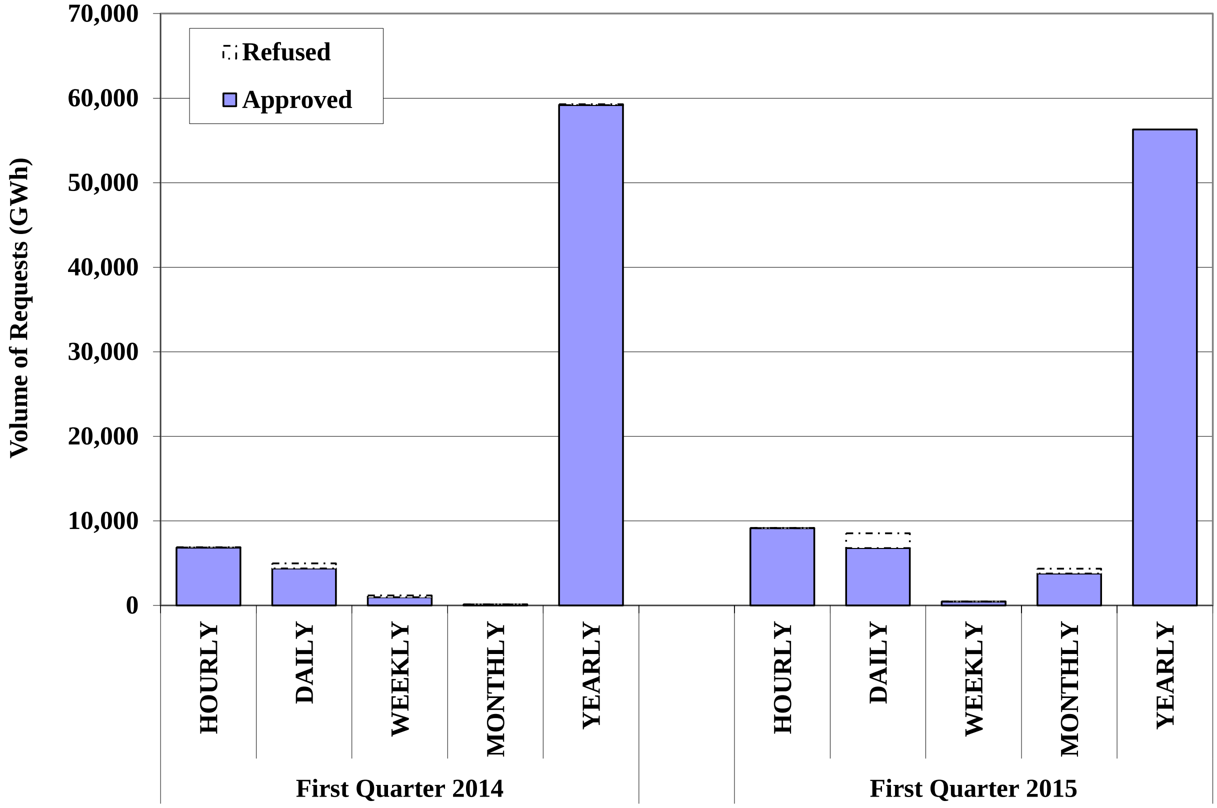


Figure 5 indicates increases in the volume of approvals from the first quarter of 2014 for hourly, daily, and monthly service increments. There was a decrease in approvals for weekly and yearly service increments. Yearly service continued to make up the largest share of transmission requests. The approval rate of requests for all increments of service except daily increased from the first quarter of 2014. There were no refusals of yearly service during the study period. The largest decrease in approval rates were for daily service (88 to 79 percent) but the volume of approved service increased by 55 percent. 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 a set of key flowgates that most limit transmission access.[8] In the AFC methodology used by Duke to assess transmission requests, transmission service is analyzed against the physical elements that a request impacts, rather than just the contract path (as was done previously in the Area Interchange methodology). 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). For area to area transfers, the TSR is approved if it does not cause 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.

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[8] The study of key flowgates takes the place of our prior analyses of key paths. Prior to the second quarter of 2011, we assessed TTC reductions that may have limited market access on key paths. Our new analysis was developed as a result of the adoption of the AFC methodology.

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

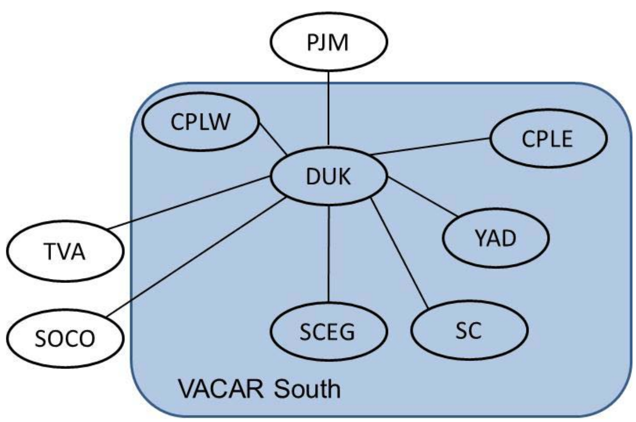
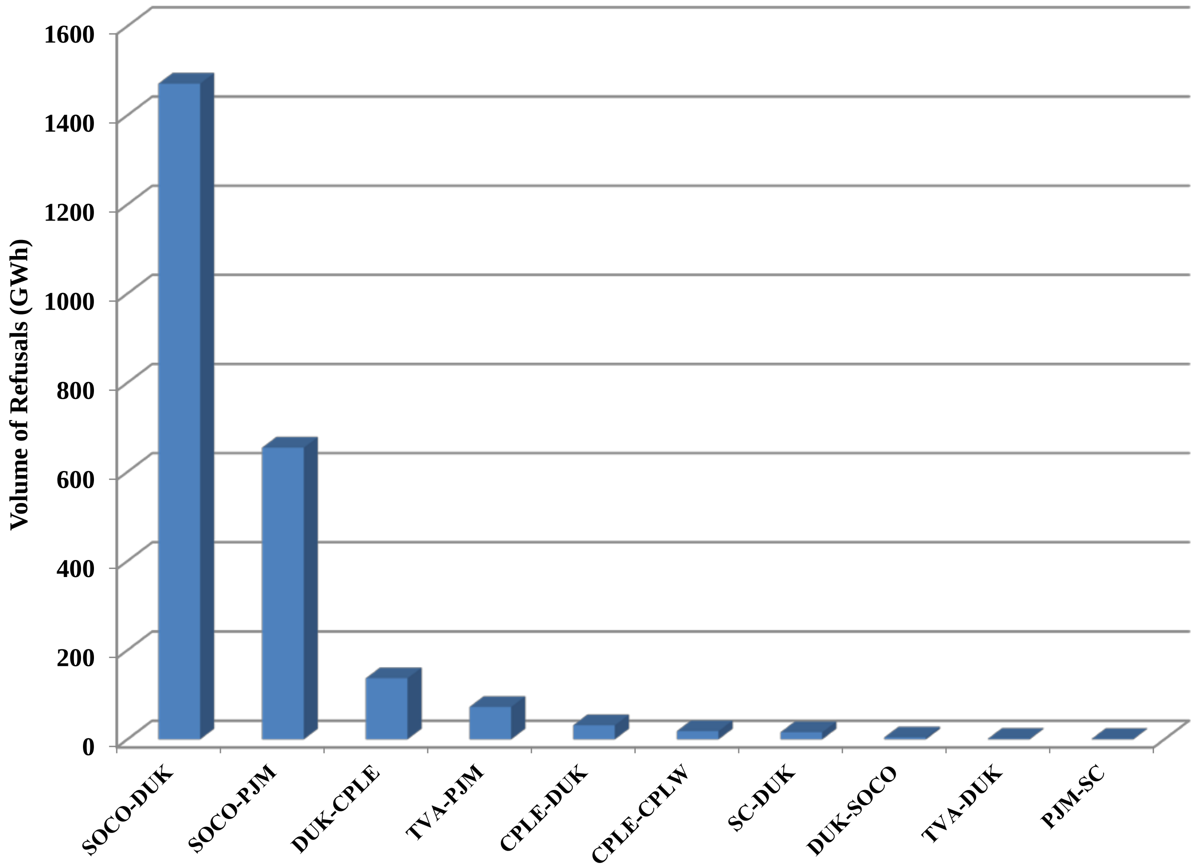


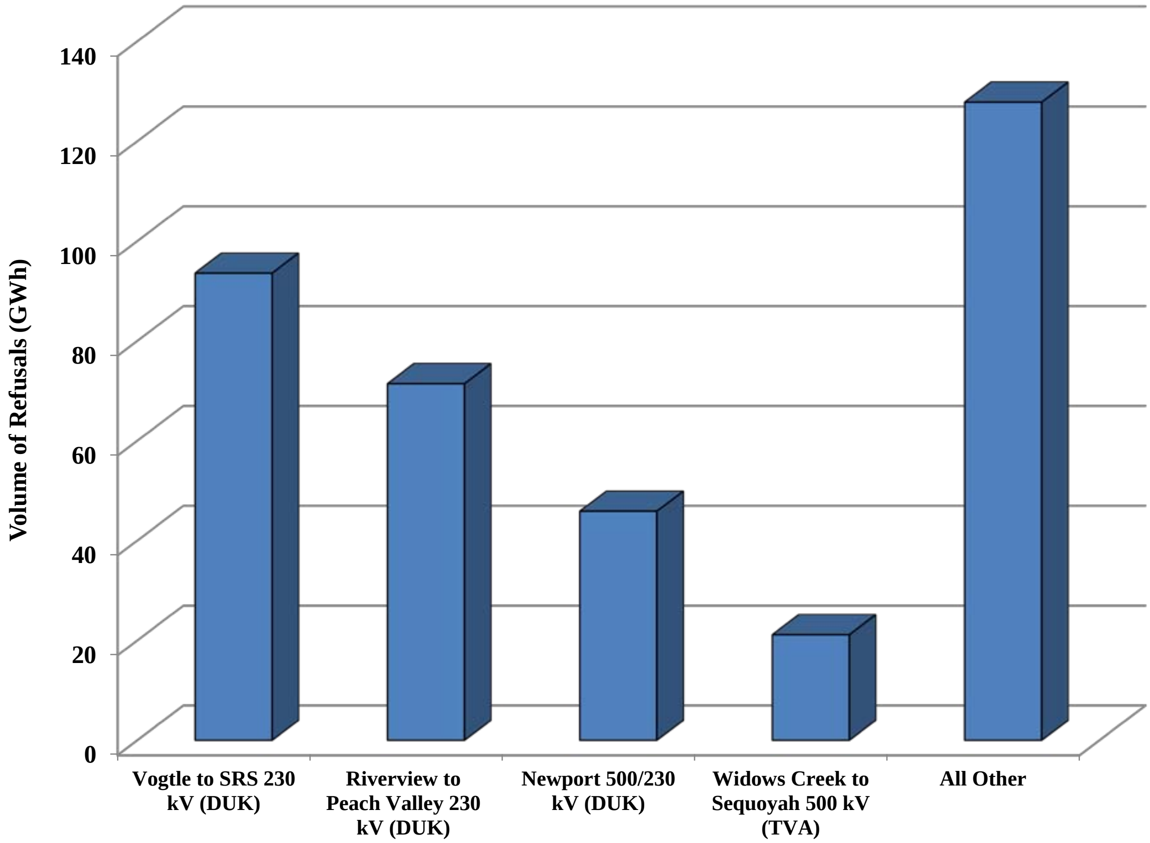
Figure 7 shows the TSR refusals on the ten paths that experienced the most refusals for service during the quarter.

Figure 7: TSR Refusals by Path
January 2015 – March 2015



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. 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.

Figure 8: Key Flowgates Linked to Current TSR Refusals
January 2015 – March 2015



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.[9]

[9] 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

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. In simple terms, 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 (flowgate rating less the modeled post-contingent flow). 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 figures, we only provide shaded bars for 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 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

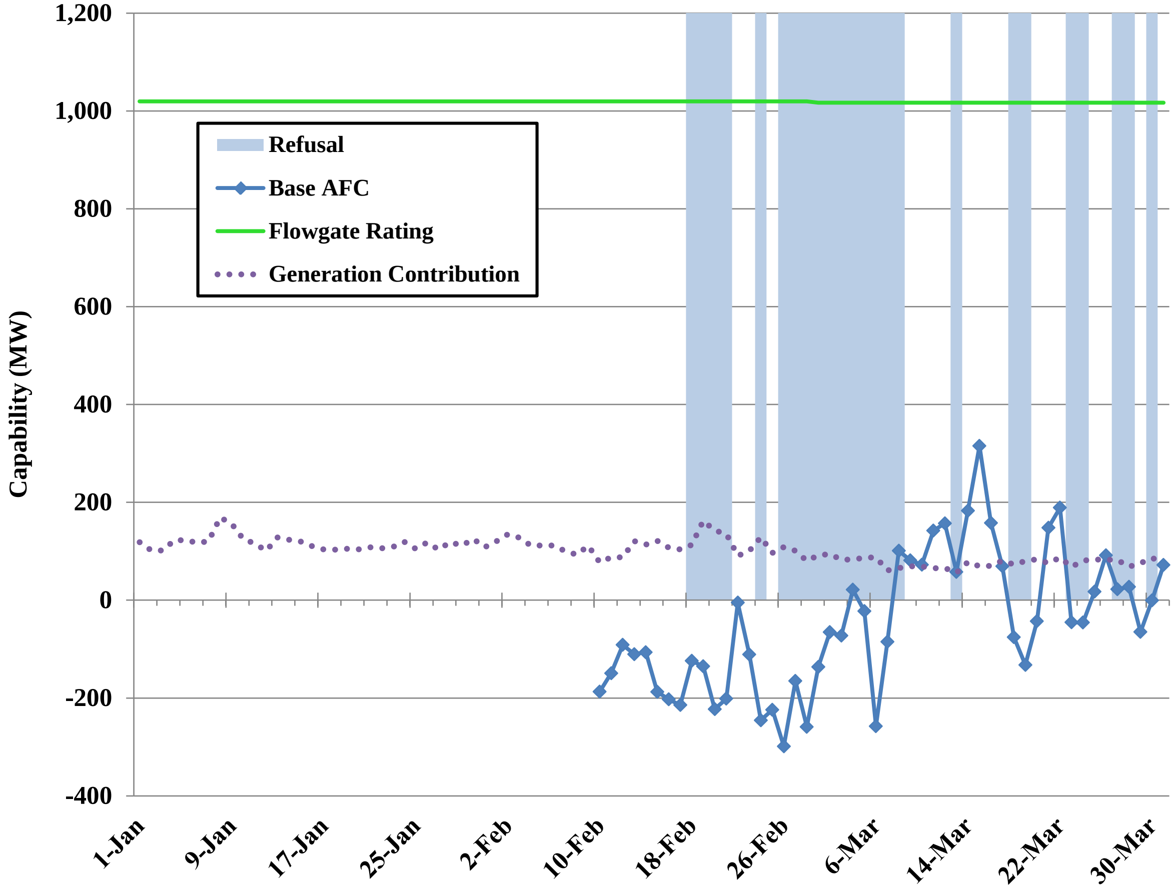
OASIS site.

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.[10] We indicate the flowgate owner as a suffix to the flowgate name. For all flowgates, we reviewed Duke transmission outages and generation operations. Study dates are selected from events where downward spikes in Base AFC were coincident with TSR refusals. We also checked for changes in flowgate ratings for Duke flowgates and in some cases, verified the accuracy of the modeling results by comparing forecasted flows with the flows observed in real-time operations. We first check to see if the 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 are within ninety percent of the 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 headroom” as the flowgate limit minus the maximum loading over the day. We then compare this “observed headroom” to the sum of the Base AFC plus the TRM, which represents forecasted headroom. If this forecasted headroom is similar to or greater than the observed headroom in real time, then the AFC process is deemed to be accurate from the perspective of not understating transmission capability. We now consider each figure separately.

[10] CPL flowgates are not treated as owned by Duke even thought 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.

Figure 9: Base AFC – Vogtle to SRS 230 kV (DUK)
January 2015 – March 2015



Vogtle to SRS 230 kV (DUK): This Duke flowgate has a contingent element of "Purrysburg to McIntosh" 230 kV and first came into use on February 10, 2015. This flowgate is a major cause of TSR refusals on the "TVA to DUK" and "DUK to SC" paths. During the quarter there were 96 daily and hourly TSR refusals associated with this flowgate.

The rating on the flowgate, displayed as a green line in the figure, was constant over the study period at 1020 MW.

As seen by the dotted purple line in the figure, the Duke and Progress generation contribution was relatively constant over the period studied and, hence, does not support a hypothesis that a change in generation dispatch caused the total flow on the flowgate to change during periods when TSRs were refused. Therefore, we do not find any significant impact caused by Duke and Progress generation dispatch or outages.

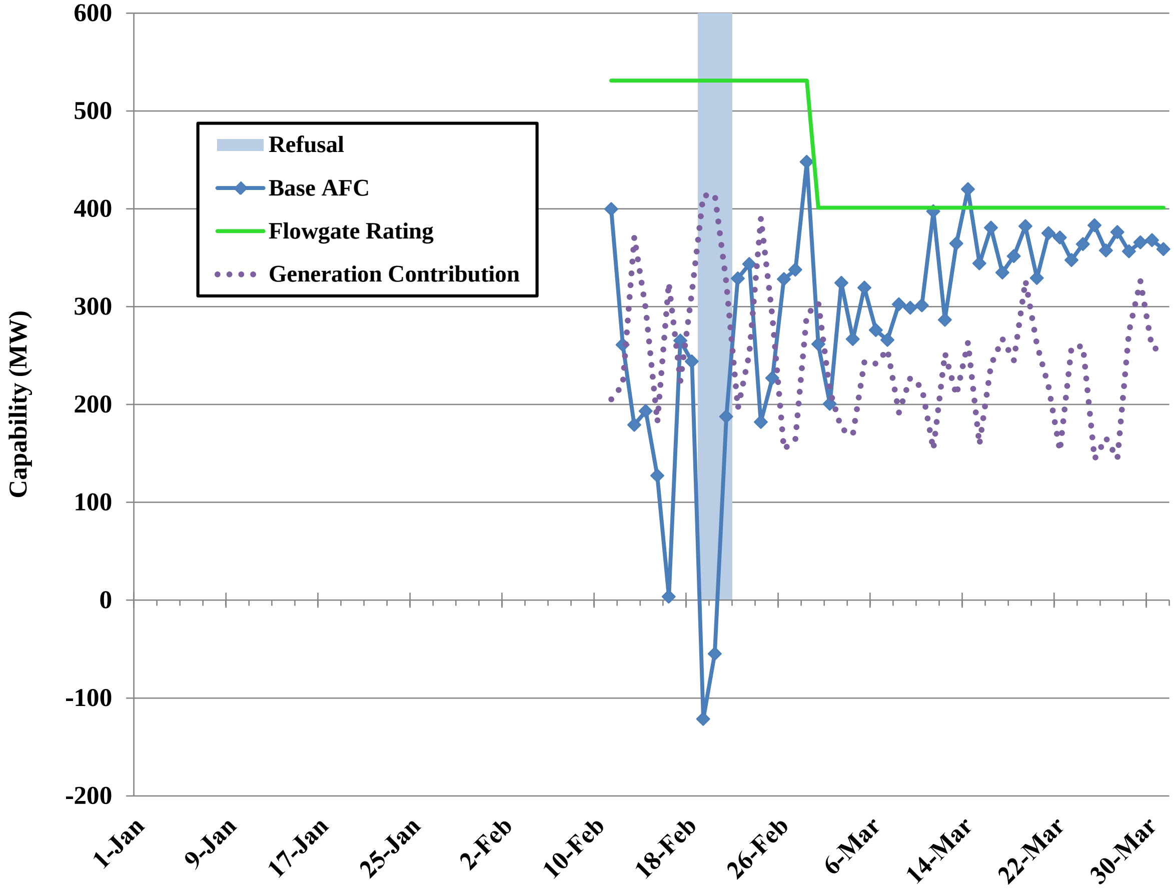
We reviewed Duke transmission outages impacting four of the days when Base AFC reductions were coincident with TSR refusals (February 20, 26, March 6, and 19) and found one transmission outage to be of interest.

- The [redacted] line was shown as out of service for March 19 on the data exchange used by the transmission providers in the region. This would affect the topology of the load flow case in the Model Builder process. However, this outage did not appear in the data or logs provided by Duke. Since the [redacted] we speculate that it was a planned [redacted] outage that never actually occurred.

Since this is a Duke flowgate, we reviewed the accuracy of the AFC process further by analyzing how close the flowgate was to its operating limits in real time during periods when the Base AFC was negative coincident with refusals (February 20, 26, March 6, and 19). We found that in real time, the flows exceeded 100 percent of the operating limit. This indicates that the day-ahead studies were accurate predictors of real-time conditions for this flowgate.

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

Figure 10: Base AFC – Riverview to Peach Valley 230 kV (DUK)
January 2015 – March 2015



Riverview to Peach Valley 230 kV (DUK): This flowgate uses the contingency of the parallel circuit "Riverview to Peach Valley" 230 kV. It started to be used for TSR review on February 10, 2015. It is a cause of TSR refusals on the "CPLE to CPLW", "DUK to CPLE" and "DUK to PJM" paths. During the quarter there were twelve hourly and daily TSR refusals associated with this flowgate.

The rating on this flowgate was revised downward from 531 MW to 401 MW on March 1, 2015, marking the switch away from the winter model.

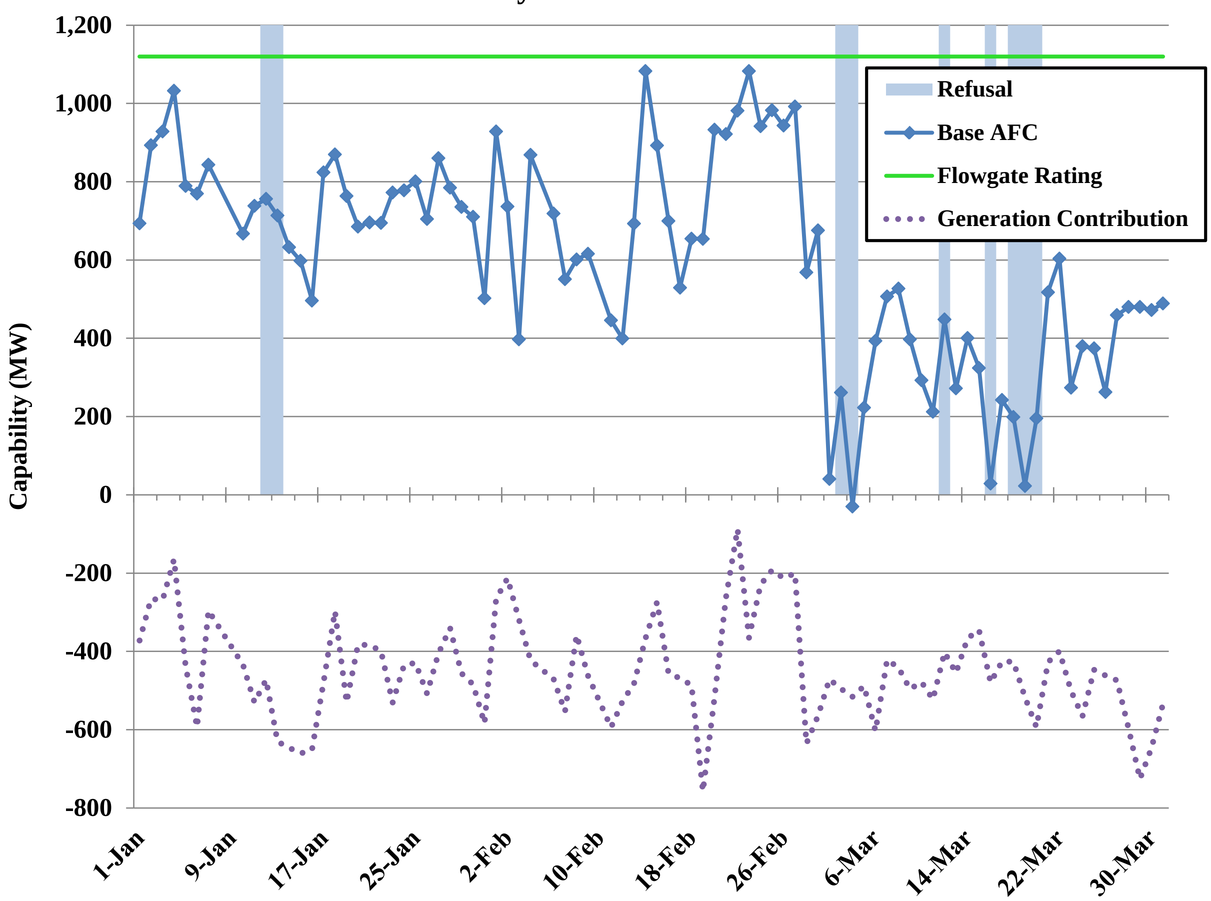
All the Duke and Progress generation has less than a [redacted] percent shift factor on this flowgate. As can be seen in the figure, influence from "Generation Contribution" on this flowgate was not positively correlated with and did not explain the variations in Base AFC. Most of the variations seen in the Generation Contribution are the result of [redacted]

We also reviewed Duke transmission outages impacting February 18 when the Base AFC was low coincident with refusals. We did not find any transmission outages that significantly affected the flowgate. Thus, we do not consider operations of Duke transmission or generation to be associated with anticompetitive conduct relative to congestion on this flowgate.

Since this is a Duke flowgate, we reviewed the accuracy of the AFC process further by analyzing how close the flowgate was to its operating limits in real time on February 19 and 20, when the Base AFC was negative coincident with refusals. We found that in real time, the flows exceeded 103 percent of the operating limit. This indicates that the day-ahead studies were accurate predictors of real-time conditions for this flowgate.

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

Figure 11: Base AFC – Newport 500/ 230 kV Transformer (DUK)
January 2015 – March 2015



Newport 500/230 kV Transformer (DUK): This flowgate uses a 500/230 kV transformer at McGuire as the contingent element. The flowgate was the cause of 34 hourly TSR refusals, mostly on the “CPLE to DUK” path.

The rating on this flowgate is constant at 1120 MW across the study period.

Our review of Duke and Progress generation contribution shows a strong correlation with Base AFC. The most significant affect is the [redacted] The unit has a [redacted] percent shift factor on the flowgate, causing nearly a [redacted] MW drop in AFC. The [redacted] units also unload the flowgate with a negative [redacted] percent shift factor. Outages at the [redacted] station are reviewed later in the report and were found to be justified. The [redacted] station is the most influential in loading the flowgate with increased generation output with over a [redacted] percent shift factor. As discuss below, we reviewed the dispatch of the [redacted] and others in the “Out of Merit Dispatch” analysis and did not find that they were operated out of merit. Thus, we do not consider operations of Duke and Progress generation to be associated with anticompetitive conduct relative to congestion on this flowgate.

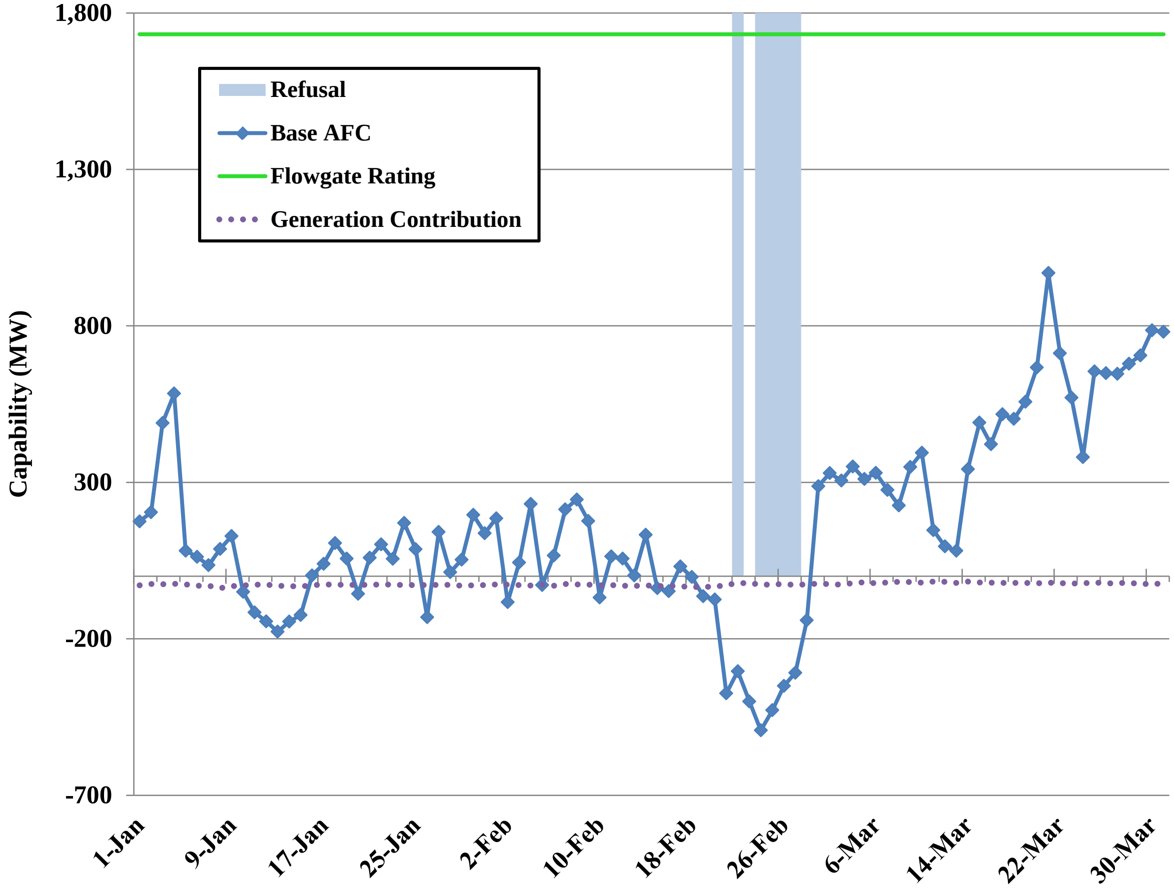
We reviewed Duke transmission outages on March 4, 16 and 19. These days showed a decrease in Base AFC coincident with TSR refusals. Two outages had a significant impact on this flowgate:

- From [redacted] through [redacted] the [redacted] kV line was out of service.
- From M[redacted] through the end of the study period, the [redacted] kV lines were out of service.

We reviewed these outages further in the Transmission Outages section of this report and found them to be reasonable and justified. Since this is a Duke flowgate, we reviewed the accuracy of the AFC process further by analyzing how close the flowgate was to its operating limits in real time during periods when the Base AFC was negative or near zero coincident with refusals (March 4, 16 and 19). We found that in real time, the flows exceeded 100 percent of the operating limit for March 16 and 19. On March 4, the flows reached 61 percent of the limit. Overall, this indicates that the day-ahead studies were accurate predictors of real-time conditions for this flowgate.

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

Figure 12: Base AFC – Widows Creek to Sequoyah 500 kV (TVA)
January 2015 – March 2015



Widows Creek to Sequoyah 500 kV TVA): This flowgate is the cause of nine Daily and Hourly TSR refusals on the "SOCO to PJM" path.

As can be seen from the Generation Contribution line in the figure, the dispatch of Duke and Progress generation had no effect on the Base AFC.

We reviewed Duke transmission outages impacting February 24 and found no outages that had a significant impact on this flowgate.

While not one of the top four flowgates, a TVA Flowgate in Mississippi (90058: 8CHOCTAW 500/8W POINT 500 CKT 1) was the cause of refusals on four TSRs for service from SOCO to PJM. Our review confirmed that the shift factors exceeded the five percent minimum, so we find the refusals to be justified. The combination of generation availability and transmission topology within SOCO and TVA that caused flows to go that far west were not under Duke's control.

Based on our evaluation of flowgates, 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. Most 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 two steps. First, for each hour, constraint and delivery point, we calculate a shift-factor-weighted[11] volume of trades by summing the product of the shift factors and the net trade volumes (purchases minus sales). For each hour and each constraint, the values are summed across all delivery points. Second, from this set of values, we select the maximum value for each day. 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.

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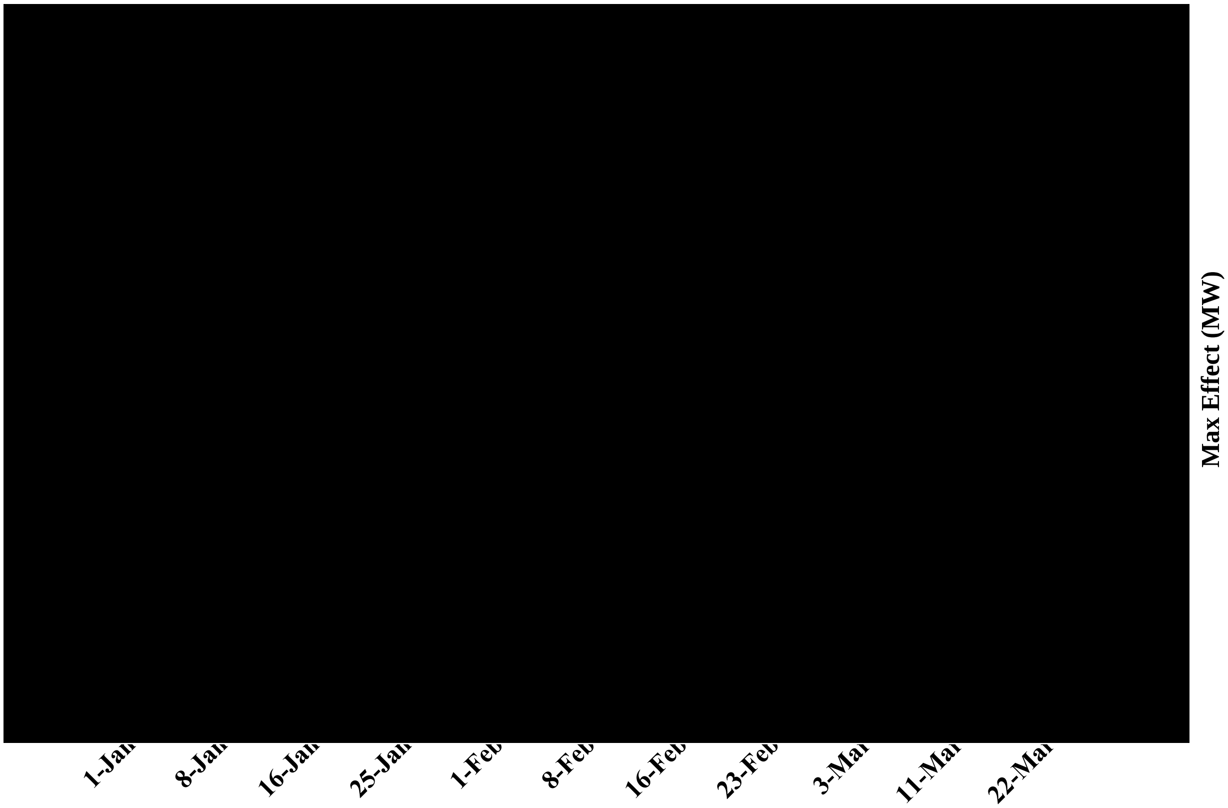
11 The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path. Shift factors between -.01 and .01 are set to zero.

Figure 13: Prices for Duke Sales and Purchases
January 2015 – March 2015



The weighted average daily price of Duke's sales ranged between $[redacted] and $[redacted] per MWh. The volume-weighted average daily sales price was $[redacted] per MWh. On days with potentially beneficial curtailments, the average sale price was $[redacted] per MWh. The weighted average daily prices of Duke's purchases range between $[redacted] and $[redacted] per MWh. The weighted average daily purchase price was $[redacted] per MWh. On days with potentially beneficial curtailments, the average purchase price was $[redacted] per MWh. The fact that on average Duke purchased power for more and sold power for less during congestion periods than the study period as a whole indicates that Duke did not benefit from the congestion. However, looking at individual days, Duke sold power on [redacted] above average costs. This occurred when there was congestion that would potentially benefit the Duke transactions. Duke purchased power at below average prices coincident with congestion that had a Max Effect greater than [redacted] MW on [redacted] We examined further those days, as well as February 19 and 20 (as noted earlier) further.

- [redacted] Duke was purchasing [redacted] MW of power from [redacted] at $[redacted] per MWh and selling [redacted] MW of power to [redacted] for $[redacted] per MWh for hour ending [redacted] [redacted] while tags from [redacted] to [redacted] were being curtailed. These circumstances indicate that Duke may have benefited from low purchases prices and high sales prices on this date.

- On [redacted] Duke was purchasing [redacted] MW of power from [redacted] at $[redacted] per MWh while the tags from [redacted] to [redacted] were being curtailed. These circumstances indicate that Duke may have benefited from low purchases prices on this date.
- On [redacted] Duke was purchasing [redacted] MW of power from [redacted] at $[redacted] per MWh while the tags from [redacted] to [redacted] were being curtailed. These circumstances indicate that Duke may have benefited from low purchases prices on this date.
- On [redacted] Duke was purchasing [redacted] MW of power from [redacted] at $[redacted] per MWh while the tags from [redacted] to [redacted] were being curtailed. Because this is a relatively high purchase price, we do not find that Duke benefited from the circumstances on this date.
- On [redacted] Duke was selling [redacted] MW of power to [redacted] for $[redacted] per MWh while the flowgate '[redacted] was in TLR. These circumstances indicate that Duke may have benefited from low purchases prices on this date.
- On [redacted] Duke was selling [redacted] MW of power to [redacted] for $[redacted] per MWh while the flowgate '[redacted] was in TLR. Because this is a relatively low sales price, we do not find that Duke benefited from the circumstances on this date.

Since circumstances indicate that Duke may have benefited from favorable transaction prices on [redacted] we reviewed further potential anticompetitive conduct on these dates in order to ensure that the constraints noted above as potentially beneficial to Duke's market positions were not caused by anticompetitive operation of generation or transmission assets.

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".[12] 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.

[12] 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

[redacted]

MW of Generation

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 a number of 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.

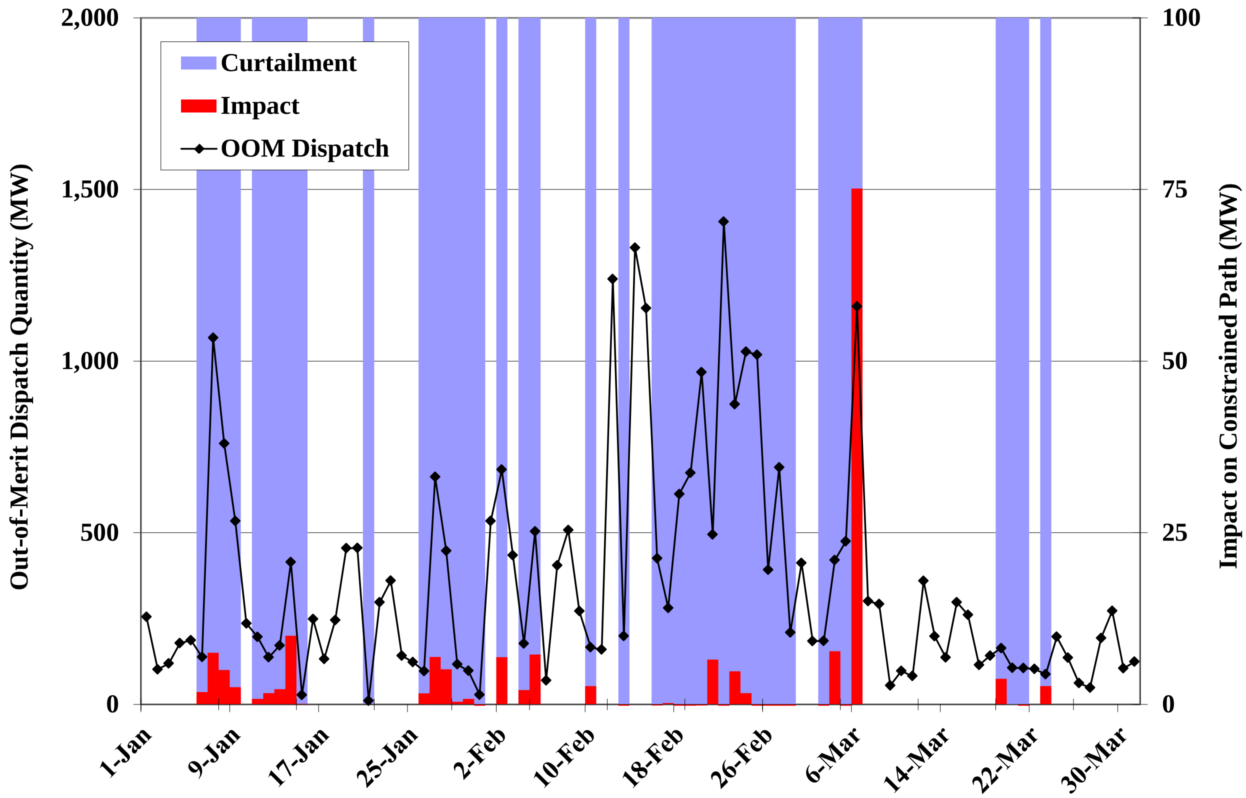
Although our analysis will tend to overstate the quantity of generation that is truly out-of-merit, the accuracy of a single instance of out-of-merit dispatch is not as important as the trend or any substantial departure from the typical levels.

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 2015 – March 2015



The figure shows 42 days with flow-based curtailments (represented by blue bars). There was one event on March 6 when impact of Duke generation on the flowgate involved in the curtailment was greater than [redacted] MW. We also reviewed the days identified for further review in the prior analysis and select [redacted] for further review in this analysis as the only days that had a positive impact.

- On [redacted] the OOM was [redacted] MW and the impact was [redacted] MW. Most of the OOM was caused by [redacted] which was at part load due to the [redacted]. Also contributing to the value were the [redacted] [redacted] and [redacted] showing OOM up, but they were actually very close to their lower operating limit. Thus we find the events for this day to be justified and find no anticompetitive conduct.

- On [redacted] the OOM was [redacted] MW and the impact was [redacted] MW. However, the cost differences between the OOM up and OOM down units were minimal, averaging less than $[redacted] per MWh. Based on the low cost difference and low impact, we do not find anticompetitive conduct.

- On [redacted] some gas generation shows OOM up driven by the gas index used to calculate its operating cost. The index and basis indicates gas at $12.48 per MMBtu consistent with Figure 1. However, Duke succeeded in sourcing gas for $[redacted] per MMBtu. At the actual gas costs, the units were not OOM.

As a result, for this quarter, we find no anticompetitive conduct associated with this analysis.

2. Output Gap

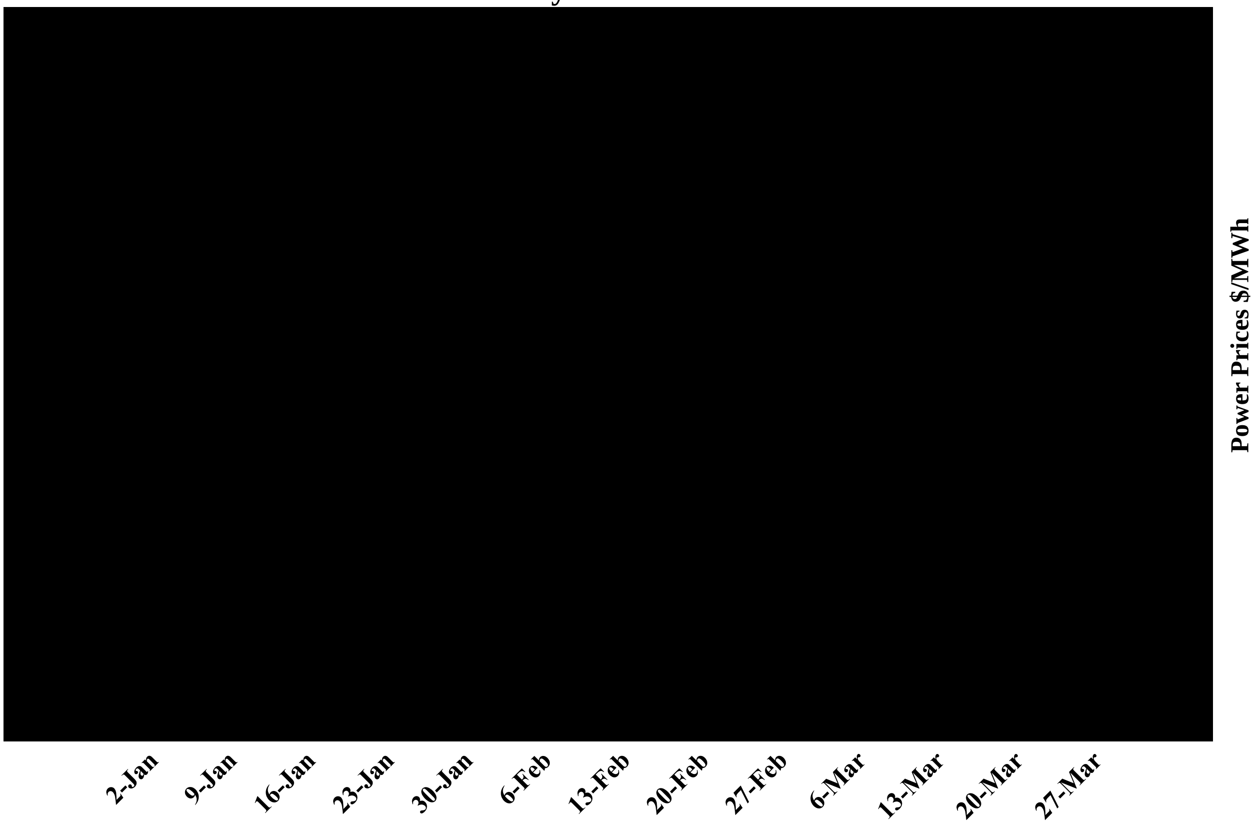
The output gap is another metric we use to evaluate Duke's generation dispatch. The output gap is the unloaded economic capacity of an available generation resource. The capacity is economic when the prevailing market price exceeds the marginal cost of producing from that unit by more than a specified 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 VACAR South 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 Platts published VACAR 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 Platts VACAR index 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 VACAR index and the PJM market prices.

Figure 16: Output Gap
January 2015 – March 2015



The composite thresholds were exceeded [redacted] times this quarter including [redacted] at the $50 threshold. However, the quantities were small not exceeding 10 MW except for on [redacted] when it was [redacted] at the $25 threshold.[13] Reviewing the days noted in the "Prices" section of this report, only [redacted] was noteworthy with [redacted] MW of output gap only on the VACAR price at the $25 threshold. This event does not appear in the figure because it doesn't have an output gap using the PJM price.

- [redacted] showed an output gap because of dispatch compensating for a gas surplus. The weather forecast for [redacted] was inaccurately cold leading to an over-purchase of gas. Burning the gas to avoid penalties cause unexpected overproduction that was absorbed by

[13] Output gaps less than 10MWare too small to be significant. Given the small magnitude and the need for Duke to maintain some operating reserves, we do not view this as indicative of anticompetitive conduct.

backing down three base-load units, which then show up in the output gap. The power wasn't sold because it was expected to be needed based on the forecast.

- On [redacted] was derated [redacted]. Repairs were scheduled to start on [redacted]

Our review of these events did not identify anticompetitive conduct.

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 VACAR price and the prices at which Duke made real-time sales.

Figure 17: Outage Quantities
January 2015 – March 2015

[redacted]

Power Prices $/MWh

Our primary interest is in unplanned generation outages that cause increases in market prices. We reviewed the data for increases in forced outages coincident with increases in market prices and found potential concern on January 8, 9, February 12 and March 5. We reviewed these days and the days identified for further review in prior analyses and found the following:

- The [redacted] MW Allen [redacted] was in a [redacted] unscheduled outage starting on [redacted] 2015 to address [redacted]. The [redacted] were caused by a [redacted]
- The [redacted] was in a [redacted] unscheduled outage starting on [redacted]
- The [redacted] returned from a nearly [redacted] following repairs to the [redacted].
- The [redacted] MW [redacted] went into an unscheduled outage on [redacted] due to a [redacted] The outage extended through the balance of the study period.

Our review of these generation outages found no evidence suggesting that these outages were not justified.

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 VACAR price and the Duke short-term sales price. This figure reveals patterns similar to Figure 17. The average planned outage rate was approximately twelve percent and decreasing towards the end of the quarter. This pattern is consistent with the expected seasonal pattern of planned outages. The average unplanned outage rate was approximately five percent. Relative to the Duke sales prices, the figure does not reveal any additional concerns.

Figure 18: Outage Rate

[redacted]

Power Prices $/MWh

1-Jan 9-Jan 17-Jan 25-Jan 2-Feb 10-Feb 18-Feb 26-Feb 6-Mar 14-Mar 22-Mar 30-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 2015 – March 2015

	Correlation with VACAR Index	Correlation with Duke Real-Time Sales Prices
Planned Outages	-34%	-35%
Unplanned Outages	23%	55%

Figure 19 reports both planned and unplanned outages. Planned outages are generally scheduled for off-peak periods when prices are lowest. Thus, the negative correlation of the planned outage rate with the VACAR index price and Duke real-time sales prices is expected. 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 VACAR index. The correlations of the unplanned outage rate with Duke real-time prices were moderate in the quarter. This is driven by the generation outages described above. Since the outages were justified we do not view the correlation as an indication 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. There were 591 transmission outages that were included in the AFC model builder process and at the same time affected power flows on elements rated 100 kV and higher during the period of study. We reviewed a subset of these outages with a focus on conditions that would have reduced transfer capability on the key flowgates when TSRs were refused or schedules were curtailed, or may have affected market access during the key days identified in the "Purchases and Sales" analysis presented earlier. We identified the following transmission outages as potentially relevant to the market based on how the outage affected the key flowgates discussed above (see Figure 8):

- [redacted]*:* This two-month outage commenced on [redacted] and was taken to rebuild the [redacted], enabling upgraded ratings. The outage affected flow on the [redacted], which contributed to a number of TSR refusals.
- [redacted] To provide clearance for the above [redacted], there was a series of [redacted] commencing on [redacted] affecting the [redacted]. Some of these outage affected flow on the [redacted] transformer, which contributed to a number of TSR refusals.
- [redacted] This [redacted] was out of service on [redacted] three days to perform preventive maintenance. The outage affected flow on the [redacted], which contributed to a number of TSR refusals.
- [redacted] This [redacted]-day outage commenced on [redacted] It was taken to repair a [redacted]

- [redacted] This [redacted]-day outage commenced on [redacted] and was taken at the request of the [redacted] The outage provided clearance for maintenance activities. The outage affected flow on the [redacted] which contributed to a number of TSR refusals.

Through our investigation of the outages and based on a review of documentation and logs, we find these outages were reasonable and justified. Accordingly, our analysis of transmission availability did not indicate that Duke reduced market access through unjustified transmission outages.