Georgia Power's Uneconomic Coal Practices Cost Customers Millions

How Ratepayers Pay Extra for Georgia Power's Coal Fleet

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EXECUTIVE SUMMARY

This report demonstrates that Georgia Power regularly operates its coal-fired power plants in such a way that the costs of operating those plants far outweigh the benefits that ratepayers receive. **Specifically, from 2017 to 2020, Georgia Power's uneconomic unit-commitment practices resulted in an estimated $232 million in excess costs for ratepayers.** Our analysis looks at how often Georgia Power commits its generating units uneconomically. We define uneconomic commitment periods as the periods of time in which the unit's operating costs (fuel and variable operations and maintenance costs) exceed the value of the generation produced by that unit. We find that Georgia Power has consistently chosen to commit its coal plants in place of less expensive generation, burdening ratepayers with costs well above the cost of energy from other available sources. For the purposes of this report, this cumulative $232 million difference represents excess costs incurred because of uneconomic commitment decisions by Georgia Power.

Large coal-fired generating units have traditionally been designed for baseload power, running in most hours of the year at a high percentage of their maximum output. These coal-fired generators have high startup and shutdown costs and are slow to ramp up and down; thus, when plant operators decide to turn a unit on, referred to as "unit commitment," it is with the knowledge that the unit cannot be turned off quickly and easily. Over the last decade, however, low gas prices and a greater penetration of renewables have upended historical patterns of electricity generation. Solar, wind, and gas-fired generators, with their zero to low variable costs of operation, are increasingly being called upon to generate, or dispatch, ahead of more expensive coal-fired generators. In a given hour, generators are stacked by their variable cost in order from lowest to highest and dispatched accordingly to meet electric demand in that hour. The variable cost of the most expensive generator used to meet load, the marginal generator, then sets the marginal price of energy in the hour (referred to in vertically integrated service territories as the "system lambda"). In some hours, coal units may be running as a result of a previous commitment decision but operating at a higher variable cost than the system lambda: they are running, but outside of the stack that determines prices. In these instances, a coal unit is said to have been "committed uneconomically."

While Georgia Power has recently signaled an intent to retire the majority of these uneconomically dispatched coal units by the end of 2028, in the years leading up to retirement, ratepayers could be subject to hundreds of millions of dollars in unnecessary expenses if the Company continues to commit its units uneconomically.

The first section of this report defines unit commitment and further describes the differences between committing a generating unit economically versus uneconomically. The second section analyzes Georgia Power's unit-commitment practices using publicly available data. It then details the excess costs born by the Company's ratepayers over the four-year analysis period. Section 3 describes other potential impacts of uneconomic unit commitment while Section 4 outlines potential remedies. Finally, the last section of this report details our specific recommendations for the Georgia Public Service Commission with respect to Georgia Power's unit-commitment practices.

1. WHAT IS UNIT COMMITMENT?

1.1. Unit Commitment and Dispatch

Coal-fired generating units have long been designed to serve baseload need for power, which is the minimum amount of electricity needed on the grid at any given time. Intermediate and peaking power plants, on the other hand, have traditionally been used to meet fluctuating demand for electricity. Baseload coal-fired units are quite inflexible relative to their intermediate and peaking counterparts and were designed to stay online for weeks or even months at a time due to lengthy startup and shutdown times. In fact, a coal plant might need to operate for a day or more both before and after it is needed, simply to account for startup and shutdown requirements.

The term “unit commitment” refers to the decision to either keep the unit online, bring a unit online that is not currently generating, or bring offline (de-commit) a unit that is currently online. Unit-commitment decisions are distinct from “dispatch” decisions, which are the decisions to incrementally increase or decrease a unit’s generation between its minimum and maximum operating levels. Fast-start units like combustion turbines or battery storage can generally be dispatched from idle (or blackstart) and do not need to be committed ahead of time. However, large steam boilers require advanced commitment, and once committed to operate, must run at a minimum level of output. As the owner and operator of its own fleet of power plants, Georgia Power, like its neighboring utilities in the southeast, is responsible for making unit-commitment and dispatch decisions for multiple types of generating units every day.[1]

Given long startup and shutdown times, coal plant owners like Georgia Power need to decide in advance whether it makes sense to commit their coal units. These decisions should be based on multi-day projections that compare the costs to operate the coal plant against the cost to generate or procure electricity from elsewhere. Overall, it may be economic to commit a coal unit when the projected costs of serving equivalent energy from other sources, including the broader market, are higher than the costs of operating the coal unit over a period of days. Because coal units are not nimble and cannot easily turn on and off, they often run at a loss for numerous hours or even days to provide value during a small segment of hours when the cost of energy is projected to be high.

Most other assessments of unit-commitment practices have looked at utilities that operate within broader Regional Transmission Organizations (RTO) or wholesale electric markets, where the market cost of energy is clearly defined. This report examines Georgia Power, which does not operate in a liquid

[1] This is contrast with many other parts of the United States, in which generating units are committed and dispatched into a central market (a Regional Transmission Organization) operated by an independent system operator. In these markets, the system operator is generally responsible for making dispatch decisions based on market bids, but commitment decisions can be made by either the utility or the system operator.

wholesale energy market. Nonetheless, Georgia Power, and indeed the whole of the Southern Company system, conducts trades of its energy on the basis of the marginal system cost of energy, or "system lambda." In this assessment, we use system lambda as a proxy for a market cost of energy, or the cost of the next most expensive source of energy.

This report analyzes how often Georgia Power commits its units uneconomically. We define uneconomic commitment periods as the periods of time in which the costs to operate a unit exceed the value of the generation produced by that unit. Our analysis demonstrates that Georgia Power regularly commits its coal units in such a way that the costs of operating those plants far outweighs the benefits that ratepayers receive. Georgia Power is actively making the decision to operate its coal plants even when there are cheaper sources of generation, in large part because the company has a monopoly with captive ratepayers. Given that Georgia Power is allowed to pass the losses that result from uneconomic unit commitment along to ratepayers via their monthly electricity bills, the company has no incentive to stop using these plants.

1.2. Unit-Commitment Costs and Considerations

In a non-centralized market, utilities like Georgia Power are responsible for internally committing and dispatching their own generating units. These utilities generally rely on internal processes that project the marginal production cost to operate each unit. Resources are committed and dispatched based on marginal cost, with the lowest-cost resources coming online first, and progressively more expensive units being turned on until system load is met. The last unit needed to meet system load sets the system marginal cost (system lambda). The unit-commitment and dispatch processes should be based on economics and should generally ensure customers are served by the lowest-cost resources while maintaining reliability. But when units are committed uneconomically, meaning based only on some portion of their full marginal cost, these units cut the line and are committed and dispatched in place of lower cost available resources. This is problematic because ratepayers still see the full unit cost, even though a lower cost was used for unit-commitment and dispatch purposes.

The process of unit commitment requires that the operator make a projection to determine if a unit's variable cost of production (inclusive of other commitment costs such as startup costs) is lower cost than other resources in the system, or specifically the marginal energy resource, over a period of days. For our purposes, we use the fuel cost and the variable operations and maintenance (O&M) costs as the variable cost of production. We use the system lambda as a proxy for the cost of the next most expensive unit in the Southern Company system. In short, for a unit to have committed economically, the unit's variable cost of production is reasonably expected to be, in aggregate, lower cost than the marginal cost of energy for the entire system over the next day or days.

When a coal unit is committed to operate, it must generate a minimum amount of energy, called the "economic minimum." The economic minimum is the lowest amount of generation that a thermal unit can safely and efficiently maintain. Importantly, the commitment decision stands independently of hour-to-hour dispatch: a unit committed may be dispatched up to its maximum output if its marginal cost is lower than alternatives but cannot be dispatched below its economic minimum if its marginal cost is higher than alternatives. In most coal-fired power plants, the economic minimum is somewhere between 40 and 60 percent of the unit's peak capacity, meaning that a committed coal plant will operate with at least half of its energy output, regardless of short-term energy price changes.

When a unit is uneconomically committed, it is said to be run "out of merit," i.e., it displaces units that would have been less expensive to operate. Turning on a more expensive generator, when other lower cost resources could be dispatched first, results in excess costs to ratepayers (who must pay for the full fuel and variable costs associated with uneconomic unit operation). And while no projection is ever guaranteed to be correct, including those informing unit-commitment decisions, generation owners that ignore or sideline commitment economics do a disservice to their bottom line. In the case of rate-regulated utilities, they do a disservice to their ratepayers.

Merchant coal generators, or those that rely on market-based revenues, do not have the luxury of making uneconomic commitment decisions: uneconomic commitment decisions could result in unsustainable losses to generation owners. Studies have found that these merchant generators are much less likely to make uneconomic commitment decisions than their regulated counterparts.[2] However, rate-regulated utilities such as Georgia Power regularly pass fuel and operational expenses on to customers, and often with little rigorous oversight. Many utility regulators simply assume that plants are prudently operated and allow costs to be passed through on a pro-forma basis. This report demonstrates that Georgia Power's customers incurred hundreds of millions of dollars in uneconomic operations due to poor unit-commitment practice in the last few years alone.

Why might a utility commit its units uneconomically?

Utilities often give several reasons for committing their units uneconomically. First, frequent startup and shutdown of coal units, known as "cycling," can increase wear-and-tear at the units and increase maintenance costs. Utilities might force units to stay online to avoid incurring unit cycling costs. But this practice also generally results in the incurrence of unnecessary operational costs well in excess of the cycling costs being avoided. While it is reasonable for a utility to minimize cycling, commitment costs (including startup costs) and commitment times can and should be included in unit-commitment analysis.

Second, utilities are often contractually obligated to receive a specific number of tons of coal or pay a penalty. This may result in fuel over-supply, and to manage that over-supply, some utilities will simply keep the unit online without regards for economics. Others will artificially lower a unit's marginal cost by a calculated amount that is tied to the cost of managing the excess fuel supply. This should only occur when the utility has calculated that it is cheaper to uneconomically keep a unit online to burn excess fuel than to store it, sell it, or buy out a contract. This justification also presumes that the fuel contracts

[2] Potomac Economics. September 2020. *A Review of the Commitment and Dispatch of Coal Generators in MISO.* Available at https://www.potomaceconomics.com/wp-content/uploads/2020/09/Coal-Dispatch-Study_9-30-20.pdf.

were executed prudently and with the approval of the Commission, which obligates ratepayers to cover the fuel costs; however, this is frequently not the case.

Third, as mentioned above, production cost only includes those costs which can be considered variable. Utilities often categorize specific fuel and fuel transportation costs as fixed, and thus exclude them from the production cost calculation. They generally exclude costs associated with fixed transportation contracts, fixed tonnage requirements, or must-take provisions of fuel contracts from unit dispatch and commitment decisions.[3] This practice effectively locks ratepayers into paying a portion of fuel costs, often without any formal approval from the regulatory commission. Utility judgement of which O&M costs are variable versus those that are truly fixed also varies widely, which can result in the underrepresentation of variable costs in the commitment cost.

Lastly, a utility that receives a return of and on assets in the rate base may have an incentive to show that aging units are still "used and useful" despite the substantial capital and fixed expense required to keep them online. A unit that is not economic over the long run (relative to replacement options) and does not provide economic service on a short-term basis may be perceived as not used or useful and at risk for disallowance. As noted by the U.S. Energy Information Administration (EIA), coal units that move to very low utilizations are often retired shortly thereafter because the justification for their operational costs evaporates.[4]

Is uneconomic unit commitment ever justifiable?

There are limited circumstances in which a higher cost unit might operate in place of a lower cost unit. First, sometimes units need to be brought or kept online for testing purposes or in anticipation of a reliability need. These decisions may be made regardless of costs and are reasonable, but a prudent utility manager would also document such practices to justify the period of uneconomic operation.

Second, given the inflexibility of coal units, it can sometimes make sense to leave a unit online for short periods of time, even when there are lower-cost resources available, in order to be available to provide electricity during hours of high demand. However, the unit must be projected to be economic overall across a multi-day or week period (inclusive of all commitment costs) to avoid excess, unjustified costs to ratepayers.

Lastly, actual conditions may be different from utility projections. If system demand or the availability (or cost) of alternative energy opportunities differs significantly from what the utility projected, the utility's commitment decisions may not minimize costs to ratepayers during a multi-day period. If the utility's own contemporaneous analysis indicated that operating the unit would minimize costs, their decision was not necessarily an imprudent one. If, however, a pattern exists in which the utility's

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[3] Based on our review of publicly available data, we do not believe Georgia Power engages in this practice.

[4] U.S. Energy Information Administration. 2020. *As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation*. Accessible at https://www.eia.gov/todayinenergy/detail.php?id=44976.

forecast is consistently and systematically wrong, and the utility has neglected to modify its decision-making process, its entire process may not be robust or prudent. The accuracy of the utility's daily unit-commitment decision-making process should itself be fed back into its decision-making process, with modifications incorporated when the current process is falling short.

2. Georgia Power's Unit-Commitment Practices

Synapse Energy Economics analyzed Georgia Power's unit-commitment practices for its coal fleet from 2017 through 2020 using publicly available data from the U.S. Energy Information Administration (EIA), the U.S. Environmental Protection Agency (EPA), and the Federal Energy Regulatory Commission (FERC). Our assessment of unit commitment examined all of Georgia Power's coal units that were operational during any part of our four-year analysis period. A more detailed description of data sources and methodology is presented in Appendix A.

We find that Georgia Power consistently committed each of its coal units out of merit (i.e., uneconomically), thereby burdening ratepayers with costs well above the cost of energy from other available sources (defined as the marginal system cost, or system lambda). Specifically, from 2017 to 2020, Georgia Power's uneconomic unit-commitment practices resulted in an estimated $232 million in excess costs for ratepayers. For the purposes of this report, this cumulative $232 million difference between unit costs and system lambda on an hourly basis is intended to represent excess costs incurred based on uneconomic commitment decisions. To avoid incurring these costs, Georgia Power did not have to make substantial investments or long-term commitments to cheaper resource portfolios. Instead, these excess costs were avoidable simply through better operational practices.

There may be certain instances in which the units were committed economically at their unit minimums but dispatched uneconomically above these minimums. Given the magnitude of the excess costs, we believe these instances are minimal; however, because we rely exclusively on public data for this analysis, we were unable to isolate them in this analysis. Detailed methodology is provided in Appendix A, along with a description of the data that are necessary to do a more in-depth analysis.

Our aggregate results of $232 million in excess costs is a conservative estimate of the amount unnecessarily passed on to ratepayers over the past four years (2017–2020). We classify this result as conservative because without an anomalous weather event in 2018, which led to a spike in the system lambda, excess costs would be even higher. Specifically, we found that in each of 2017, 2019 and 2020, all of Georgia Power's coal plants incurred operational costs in excess of the marginal cost of energy. In January 2018, though, a "bomb cyclone" hit the U.S. Southeast and disrupted electricity supply for almost the entire month.[5] In that one month, the marginal cost of electricity tripled due to frozen pipes and disrupted service at refineries, as shown by the spike in the system lambda in

Figure 1 below.[6] During that time, the prevailing marginal cost of energy actually briefly exceeded the cost of operating Georgia Power's coal plants.

The tables and charts on the following pages demonstrate how and when these excess costs occur and demonstrate the magnitude of uneconomic coal commitment on Georgia Power's system.

Figure 1 compares the average monthly system lambda to our estimated cost of production at each Georgia Power coal unit. McIntosh and Hammond were the most expensive units on the system prior to their retirements in 2019. Note that while the McIntosh costs are shown to be higher than the average system lambda for the month of January, there were hours in that month in which the system lambda exceeded $200/MWh, and thus specific hours in which it was higher than the plant's operating costs.

Figure 1 also shows that Bowen, Scherer, and Wansley consistently generate energy at a higher cost than the system lambda. Even more concerning is that in 2020, the problem at these three plants is getting worse, and the gap between the cost of energy at the system lambda and the marginal cost of energy for Georgia Power's remaining coal fleet has widened.

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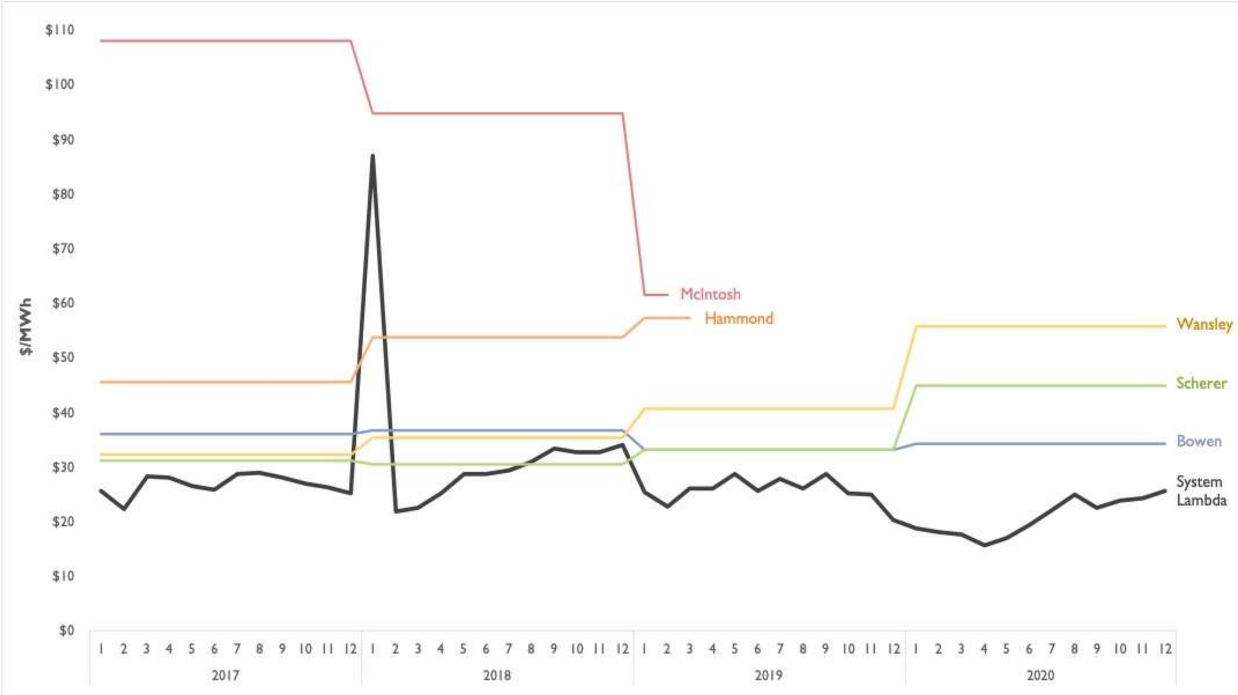
[5] Scott DiSavino, Devika Krishna Kumar. January 2018. "The 'Bomb Cyclone' Has Put a Freeze on the Power Supply in Parts of the East Coast." *Reuters*. Available at https://www.reuters.com/article/us-usa-weather-energy/bomb-cyclone-hits-u-s-east-coast-energy-power-supply-idUSKBN1ET1GS.

[6] *System Lambda from FERC 714, Marginal Cost of Production calculated from FERC Form 1, EIA-923, and EPA CAMD.*

Figure 1: Southern Company average monthly system lambda compared to estimated unit marginal cost of production (2017–2020)



Source: System Lambda from FERC 714, Marginal Cost of Production calculated from FERC Form 1, EIA-923, and EPA CAMD. Lines for McIntosh and Hammond end in early 2019 due to plant retirements.

Table 1, below, shows the excess costs of generation at each of the coal plants in each year between 2017 and 2020. As discussed above, the net positive values shown in 2018 were driven entirely by high system lambdas experienced during the January winter storm. This is the only year in the analysis period in which Georgia Power's coal fleet provided value rather than incurring excess cost to the company's ratepayers. In fact, during 46 of the 48 months during this four-year study period, the company incurred excess costs. The only two months in which the coal fleet provided net value to customers occurred in 2018—in January and December. In 2017, 2019, and 2020, Georgia Power's coal fleet operations resulted in excess costs to customers in every single month. Monthly results are shown in Appendix B.

Table 1: Annual value/excess cost of Georgia Power coal fleet, including January 2018

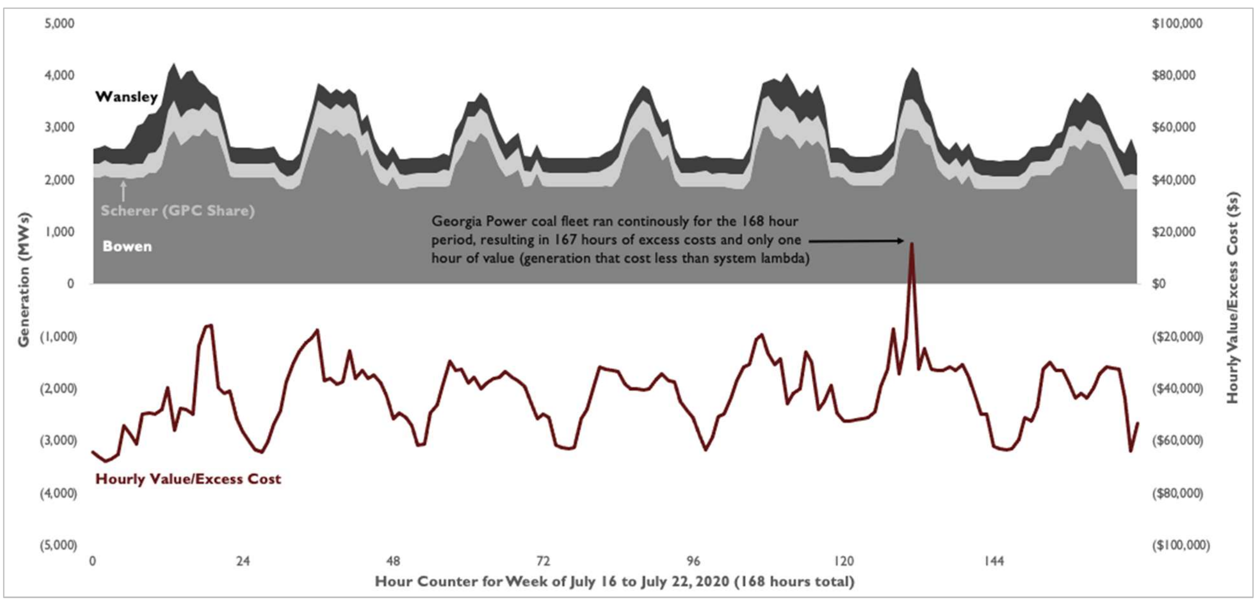
Total Value/Excess Cost ($Millions) All Months					
Year	**Bowen**	**Hammond**	**McIntosh**	**Scherer**	**Wansley**
2017	($113.8)	($7.7)	($2.1)	($7.2)	($12.3)
2018	$43.4	$11.5	$1.8	$26.7	$49.9
2019	($69.8)	($3.9)	($0.8)	($15.0)	($21.0)
2020	($78.6)	Retired	Retired	($27.4)	($6.0)
TOTAL	($218.8)	($0.1)	($1.1)	($22.9)	$10.6
				Total Excess Cost	**($232.4)**

Note: Throughout this report, all calculations for Scherer are pro-rated to reflect Georgia Power's 22.95 percent ownership share in the plant. Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

The fact that committing Georgia Power's coal units during the brief period of the bomb cyclone event failed to result in excess costs should not be an indication that overcommitment of the company's coal fleet is a reasonable strategy. For January 2018, it represents prudent commitment; in the remaining months of the year, however, the accumulation of excess costs demonstrates that the units were also committed when they were *not* needed.

Figure 2 shows results for the seven-day period from July 16 to July 22, 2020, in which the three active Georgia Power coal units—Bowen, Scherer, and Wansley—operated continuously. Out of the 168 hours in the week, the units only provided generation at a lower cost than the system lambda in a single hour. During all other hours, the cost of generation from these three coal units exceeded system lambda, resulting in excess costs to ratepayers. Across such a long timeframe, it is clear that Georgia Power either did not produce or did not follow the results of daily unit-commitment analysis. If it had, the Company would have decommitted one or more of these plants and relied on other generation resources to supply electricity to customers at lower cost.

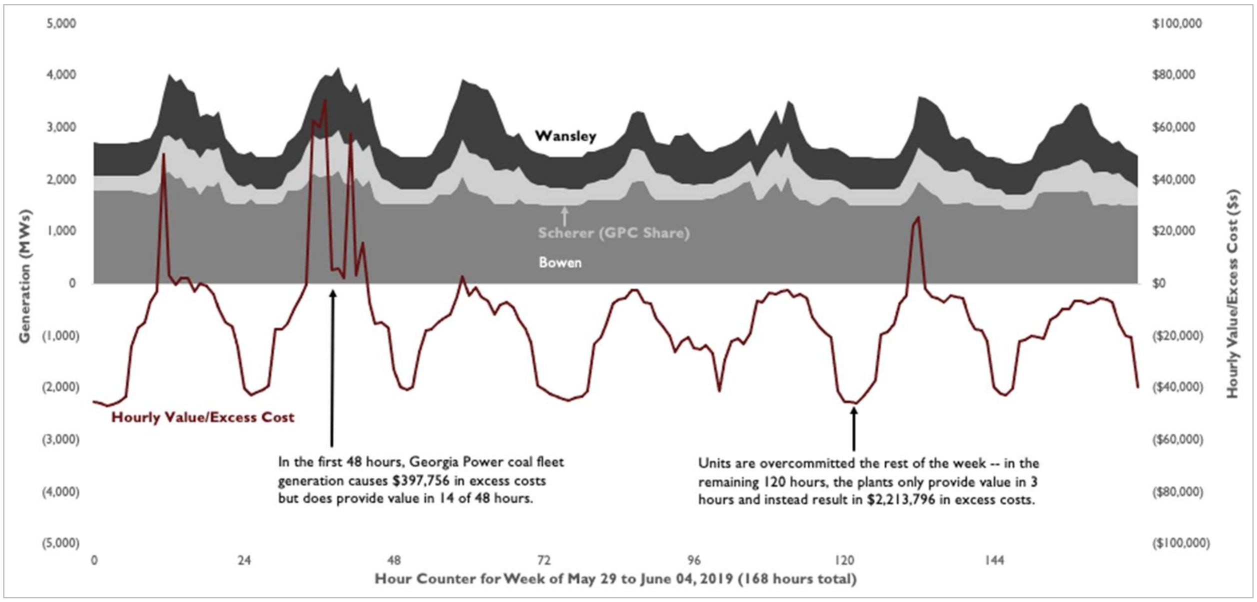
Figure 2: Coal fleet generation and hourly value/excess cost (July 16–22, 2020)



Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

While the week shown in Figure 2 is an extreme example, data in many other weeks also demonstrate that Georgia Power commits its coal units for far longer than required. During the seven-day period between May 29 and June 04, 2019, for example, the plants were online during two days with high system lambdas (even in this timeframe, the plants incurred excess costs of $0.4 million). However, as Figure 3 illustrates, the plants incurred substantial losses of over $2.2 million over the remaining five days. This indicates that it would have been more efficient to de-commit at least one if not all the coal plants during this week.

Figure 3: Coal fleet generation and hourly value/excess cost (May 29–June 04, 2019)

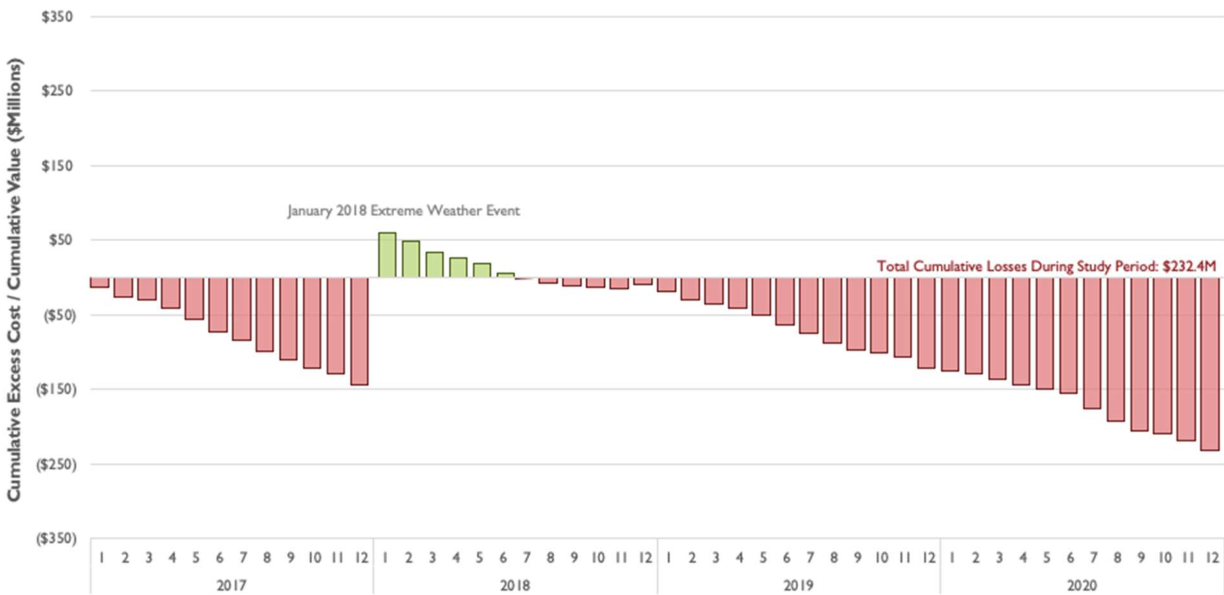


Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

Across the five Georgia Power coal plants, we analyzed 149 months of operation from 2017 to 2020, including January 2018.[7] Out of these months, Georgia Power incurred excess costs for ratepayers in 133 months, or 89 percent of the time. Figure 4 shows the accumulation of excess costs inflicted on Georgia ratepayers by Georgia Power's coal fleet. Even in 2018, the lone year that provided value due to the extreme weather in January 2018, the cumulative value trends downwards steadily. The excess costs continue to build in almost every single month, resulting in total cumulative losses of approximately $232 million by December 2020.

[7] We analyzed 48 months for each of Bowen and Scherer. We analyzed 34 months of data for Wansley due to several months in 2019 and 2020 with zero generation. We only analyzed 12 months of data for Hammond and 7 months of data for McIntosh due to months of zero generation and the retirement of each plant in early 2019.

Figure 4: Cumulative value/excess cost of Georgia Power coal fleet, including January 2018



Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

The electricity disruptions and sustained high prices seen during the bomb cyclone are not a regular event, and excluding the January 2018 paints a more accurate picture of the total excess cost caused by the operations of Georgia Power's uneconomic coal fleet. If we remove this single month from the study period, ratepayers were burdened with excess costs amounting to $435 million. Table 2 shows the annual value/excess cost if January 2018 is excluded from the analysis.

Table 2: Annual value/excess cost of Georgia Power coal fleet, excluding January 2018

Total Value/Excess Cost ($Millions) Excluding Jan. 2018					
Year	**Bowen**	**Hammond**	**McIntosh**	**Scherer**	**Wansley**
2017	($113.8)	($7.7)	($2.1)	($7.2)	($12.3)
2018	($64.2)	($1.4)	($0.6)	$3.8	($6.8)
2019	($69.8)	($3.9)	($0.8)	($15.0)	($21.0)
2020	($78.6)	Retired	Retired	($27.4)	($6.0)
TOTAL	($326.4)	($13.0)	($3.5)	($45.8)	($46.0)
				Total Excess Cost	**($434.8)**

Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

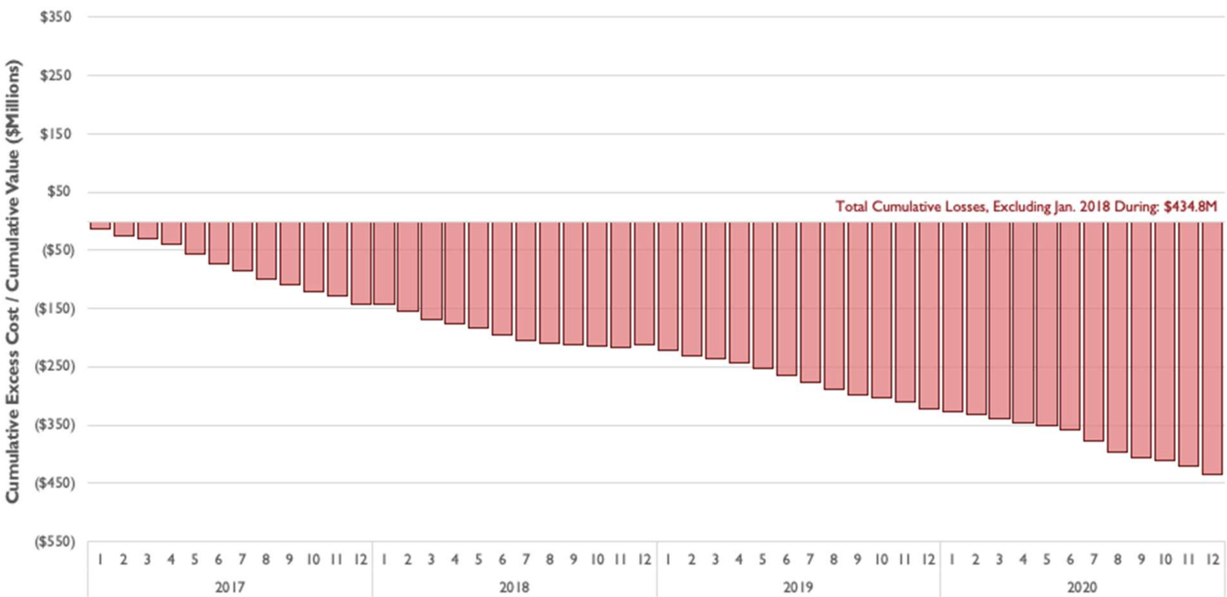
Plants Bowen and Scherer are the largest contributors to total excess costs. Hammond and McIntosh also demonstrate ongoing losses between 2017 and 2019, but these plants were committed with declining frequency prior to retirements at the beginning of 2019. Including January 2018, Wansley provided a positive energy value overall; excluding January 2018, the plant also lost value on an energy basis.

Table 3: Annual value/excess cost of Georgia Power coal fleet by unit

Total Value/Excess Costs, 2017-2020 ($Millions)		
Unit	**Total Excess Costs, All Months**	**Total Excess Costs, Excluding Jan. 2018**
Bowen	($218.8)	($326.4)
Hammond	($0.1)	($13.0)
McIntosh	($1.1)	($3.5)
Scherer	($22.9)	($45.8)
Wansley	$10.6	($46.0)
TOTAL	($232.4)	($434.8)

Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

Figure 5: Cumulative value/excess cost of Georgia Power coal fleet, excluding January 2018

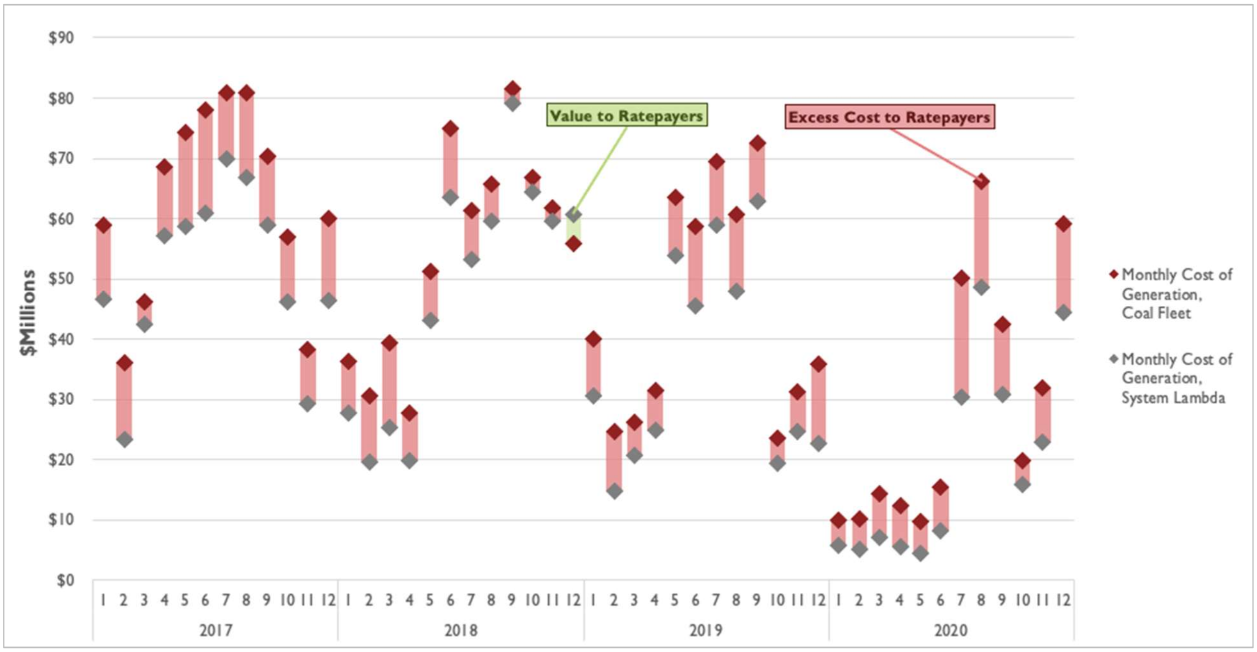


Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

The overall trend at the hourly, monthly, and annual level is clear—Georgia Power's coal fleet consistently makes its ratepayers subsidize uneconomic choices made by the utility.

Excluding January 2018, the cost of operating Georgia Power's coal fleet as whole exceeded the cost of generation from other alternatives in almost every single month from 2017 through 2020. Figure 6, below, shows the **total** variable cost of generation for Georgia Power's coal fleet on a monthly basis (red line) and the marginal cost of energy (black line).

Figure 6: Value/excess cost attributable to Georgia Power's coal fleet, 2017–2020 (excluding January 2018)



Source: Calculated from FERC Form 1, EIA-923, and EPA CAMD – see Appendix A.

In almost every month, except January 2018 and two months at the tail end of that year, Georgia Power incurred costs in excess of each plant's value at every one of the company's coal plants.

Although Georgia Power has recently signaled an intent to retire Bowen Units 1 and 2, Wansley Units 1 and 2, and Scherer Units 3 and 4 by December 31, 2028, rather than install the control equipment necessary to comply with applicable effluent limitations for flue gas desulphurization wastewater, ratepayers would still be subject to hundreds of millions of dollars in additional unnecessary expenses in those interim years if the Company does not cease its practices of committing its coal units uneconomically. Indeed, as shown above in Figure 1, the gap between the cost of energy at the system lambda and the marginal cost of energy for Georgia Power's remaining coal fleet has widened recently, and those unnecessary expenses could become even more costly unless addressed now.

3. IMPACTS OF UNECONOMIC UNIT COMMITMENT

Uneconomic unit commitment is often overlooked as an esoteric and technical issue, but it has real and negative impacts that are ultimately borne by Georgia Power ratepayers. Our assessment of Georgia Power's coal fleet from 2017 through 2020 indicates that customers overpaid for electricity by a total of $232 million, or the equivalent of $58 million each year. Figure 7 aggregates the total value (i.e., during hours in which costs were lower than system lambda) and total excess costs (i.e., during hours in which costs of generation were in excess of system lambda) showing the net value/cost. Despite the high cost of Georgia Power's coal fleet, the utility has been able to continue committing and operating these power plants because ratepayers effectively subsidize the utility's uneconomic choices through higher electricity bills.

Figure 7. Annual value/excess cost of Georgia Power coal fleet, 2017–2020

Looking ahead, the continued uneconomic unit commitment of these plants will place an undue burden on Georgia Power ratepayers. If ratepayers continue to bear these excess costs, Georgia Power has little motivation to change its unit-commitment practices, and artificially high utilization make the units appear more "used and useful" than economics would suggest. These factors, combined with remaining undepreciated plant balances, disincentivizes the utility from seriously considering the construction of new and cheaper alternatives as part of its resource planning process. This can be further exacerbated if utilities fail to accurately model the cost and likely operational practices of their aging coal fleets as part of their resource planning process.

The practice of uneconomic commitment also skews market signals upon which various stakeholders rely. This serves to further entrench existing resources. For example, Qualifying Facilities (QF)—generators that are compensated under the Public Utility Regulatory Policies Act (PURPA) of 1978—are compensated based on the avoided cost of energy as represented by the system lambda. When units are committed out of merit order, or when the unit's full variable cost is not represented in its marginal cost used for commitment decisions, the system lambda will be artificially suppressed. This suppression decreases the compensation payments made to QFs (many of which are clean energy providers), and thus discourages the entry of QFs into the market. This practice has real implications for the entire market, and for individual market participants in particular.

Utilities such as Georgia Power with captive ratepayers are expected to be regulated in a way that protects other market players and avoids incurring excessive costs for ratepayers. Uneconomic unit commitment provides these utilities a loophole. This loophole allows utilities to continue operating high-cost units and pass those excessive costs onto ratepayers, while blocking other generation alternatives that might provide a cheaper source of electricity. The Commission can manage, and even close, this loophole with adequate transparency, information, and oversight.

4. Remedies for Uneconomic Unit Commitment

Numerous commissions around the country have recognized the importance of uneconomic unit commitment, with some considering unit commitment as part of existing dockets and others initiating separate dockets dedicated to evaluating unit-commitment practices. These proceedings provide an opportunity for commission oversight and scrutiny of utility unit-commitment practices. Specific examples include the following:

- The Minnesota Public Utility Commission opened a docket titled *Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities* to review the unit-commitment practices for Minnesota Power, Ottertail Power, and Xcel Energy. This docket is ongoing.[8]
- The Indiana Utility Regulatory Commission opened a subdocket in 2020 to evaluate the prudence of Duke Energy Indiana unit-commitment practices after receiving evidence of uneconomic unit-commitment practices in a Fuel Adjustment Clause (FAC) proceeding.[9]
- The Missouri Public Service Commission has a fuel prudence review docket that occurs every 18 months. In Missouri, this prudence review supplements quarterly FAC filings.[10]
- The Michigan Public Service Commission has a power supply cost reconciliation docket annually where the prudence of utility commitment practices can be reviewed.[11]
- The Public Utility Commission of Texas has power supply reconciliation dockets every few years (the last one covered 22 months) where the prudence of utility commitment practices can be reviewed.[12]

[8] Minnesota Public Utility Commission Docket No. E99/CI-19-704.

[9] Indiana Utility Regulatory Commission Cause No. 38707-FAC123 S1.

[10] Missouri Public Service Commission, Docket No. EW-2019-0370.

[11] For example, Michigan Public Service Commission, Docket No. U-20530.

[12] For Example, the Public Utility Commission of Texas, Docket No. 50997.

There is also a growing number of reports by market monitors and other market experts that analyze the impact of uneconomic unit-commitment practices. Most of these focus on organized markets, but the principles that impact economic commitment carry over to vertically integrated areas as well.

- The Southeast Power Pool (SPP) Market Monitoring Unit (MMU) published a report in December 2019 which found that nearly half of all megawatts generated between March 2014 and August 2019 were self-committed, and that this was impacting market prices and the efficiency of market operations.[13] In September 2020, SPP staff released a subsequent report evaluating the impact of self-commitment practices in SPP. Their analysis found that around 10 percent of self-committed generation would not have been chosen for commitment and dispatch if dispatch decisions had been made on a least-cost basis.[14]

- This year, the Midcontinent Independent System Operator's (MISO) market monitor, Potomac Economics, also published a report that found inefficient commitment is a problem among a subset of integrated utilities. Further, the report found that operating resources economically would produce more efficient commitment and dispatch decisions.[15]

- Sierra Club published a paper in 2020 looking at how non-economic coal operation distorts energy markets and incurs significant costs for captive ratepayers.[16]

- Union of Concerned Scientists published a paper in May 2020 that attempted to quantify the cost of uneconomic commitment practices to utility customers in several RTOs.[17]

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[13] Southwest Power Pool Market Monitoring Unit, Self-committing in SPP markets: Overview, impacts, and recommendations, Southwest Power Pool (Dec. 2019). Available at https://spp.org/documents/61118/spp percent20mmu percent20self-commit percent20whitepaper.pdf.

[14] Southwest Power Pool Staff, Self-Commitment in SPP's Day-Ahead Market. (September 2020). Available at https://spp.org/documents/63092/2020 percent2009 percent2028 percent20commitments percent20in percent20spps percent20integrated percent20marketplace.pdf

[15] Potomac Economics. A Review of the Commitment and Dispatch of Coal Generators in MISO. September 2020. Available at https://www.potomaceconomics.com/wp-content/uploads/2020/09/Coal-Dispatch-Study_9-30-20.pdf.

[16] Fisher, Jeremy, Al Armendariz, Matthew Miller, Brendan Pierpont, Casey Roberts, Josh Smith, Greg Wannier. Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets Sierra Club, 2019. Available at https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

[17] Daniel, Joe, et al. Used But How Useful? Union of Concerned Scientists. Available at https://www.ucsusa.org/resources/used-how-useful.

5. RECOMMENDATIONS

As described above, numerous Commissions across the United States have already taken steps to analyze unit-commitment practices in more detail. We recommend that the Georgia Public Service Commission introduce its own dedicated investigation into Georgia Power's unit commitment and dispatch, like those investigations launched by the Commissions of Missouri,[18] Minnesota,[19] and Indiana.[20] This can be included as part of the upcoming 2022 integrated resource plan docket or as a separate docket on unit commitment. This type of investigation should provide transparency into Georgia Power's unit-commitment practices in several ways.

First, the Commission should require that Georgia Power provide a detailed report that describes its daily unit-commitment decisions and practices. This will inform the Commission's review of these practices and determine whether specific costs for these units have been reasonably and prudently incurred. Included in that report should be any "forecast sheets," or similar documents, for a multi-day period that are used to develop daily unit-commitment decisions and marginal costs. These sheets should memorialize the data and information that the company had on the commitment cost of all units at the time that it made its daily decisions. If there are deviations between Georgia Power's forward-looking cost-based analysis and the company's actual unit-commitment decisions, those reasons should be documented and explained.

Second, Georgia Power should disclose the different components that make up the company's marginal and average production costs. Full production costs that are or will be passed on to ratepayers should be provided, broken down by fixed costs and variable costs, including fuel, reagents or by-products, emissions, and variable O&M. The same information should be provided for the marginal production cost of each unit that is used for making unit-commitment and dispatch decisions. Georgia Power should also provide hourly data sufficient for Commission Staff to calculate the net energy value (system lambda minus all variable costs) incurred annually at each coal unit. Necessary variables would include total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable O&M cost, system lambdas, commitment status, and actual outages.

Commission oversight of Georgia Power's operational decisions provides the incentive the company needs to change its unit-commitment practices and protects ratepayers from unnecessary excessive costs. Without the Commission's protection, ratepayers have little protection from imprudent utility practices and excessive costs. Plant Vogtle has consistently garnered the headlines, but Georgia Power's coal fleet is chugging away in the background—overused, overcommitted, and costing customers money.

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[18] Missouri Public Service Commission File No. EW-2019-0370

[19] Minnesota Public Utilities Commission Docket E-999/CI-19-704

[20] Indiana Public Service Commission Cause 38707 FAC 123, Subdocket 1.

Appendix A. GLOSSARY

Capacity: The maximum output, commonly expressed in megawatts (MW), that a generator can supply to system load (adjusted for ambient conditions).

Gross Generation: The total amount of electric energy produced by a generating unit, measured at the generating terminal in kilowatt hours (kWh) or megawatt hours (MWh).

Marginal Cost: The change in production cost that results from generation of an additional unit of electricity.

Net Generation: The amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA).

Ramp Rate: The increase or reduction in plant output per minute, expressed either as the percentage per minute or MW per minute.[21]

Regional Transmission Organization (RTO) / Independent System Operator (ISO): An independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system.

System Lambda: The marginal cost of electricity as determined by the dispatch of the resources on the system to economically and reliably serve customers. Specifically, it is the incremental cost of the generating unit(s) that will serve the next increment of load.[22]

Unit Commitment: The decision to either keep the unit online, bring a unit online that is not currently generating, or bring offline (de-commit) a unit that is currently online.

Unit Dispatch: The decision to incrementally increase or decrease a unit's generation between its minimum and maximum operating levels.

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[21] Wartsila. Accessed November 3, 2021, wartsila.com. "Combustion Engine vs Gas Turbine: Ramp Rate."

[22] Georgia Public Service Commission Docket No. 4822, September 18, 2020. Direct Testimony of Georgia Power Company Witnesses Jeffrey R. Grubb, A. Wilson Mallard, and Jeffrey B. Weathers, 35:14-17.

Appendix B. Data Sources and Methodology

Synapse Energy Economics analyzed Georgia Power's unit-commitment practices for its coal fleet from 2017 through 2020 using publicly available data from the U.S. EIA, the EPA, and the FERC. The types of data used in this analysis are shown in Table 4, along with their sources.

Table 4. Sources of data used in the analysis of Georgia Power's coal fleet

Dataset	Overview and Purpose
FERC Form 1	Annual fixed/variable/fuel costs
EIA 923	Annual net generation
EIA 714	Hourly system lambda for the Southern Company system
EPA CAMD	Hourly gross generation for each unit

Our assessment of unit commitment examined the following Georgia Power units:

- Bowen
- Hammond (retired in 2019)
- McIntosh (retired in 2019)
- Scherer (22.95 percent ownership share)
- Wansley

While utilities treat exact unit cost data as confidential, they are required to disclose their total fuel and operational costs on an annual basis in FERC Form 1. Net generation is also disclosed on an annual basis in FERC Form 1 and EIA 923. The combination of annual fuel costs (provided in dollars) and annual generation (provided in megawatt-hours) allowed us to calculate an average fuel cost per MWh.

Fuel cost is only part of the unit-commitment decision. The marginal cost of production that a utility uses to commit units also includes all variables costs, which can also be expressed in $/MWh. However, there can be a grey area between fixed costs, which should not be part of unit-commitment decisions, and variable costs, which should be included in unit-commitment decisions. While the fuel costs disclosed in FERC Form 1 are accurate, the "production cost" information disclosed in FERC Form 1 represents a mix of fixed and variable costs, so using that information directly inflates the cost of operating a unit.

Instead, Synapse used a ratio of fuel costs to variable costs that offers a conservative estimate of operating Georgia Power units. Across the range of rate cases, fuel cost dockets, and other proceedings in which Synapse contributes, variable costs make up 10–15 percent of the total production cost while fuel costs make up 85–90 percent of the total production cost. To be conservative, we used the annual fuel costs from FERC Form 1 as 92 percent of total production cost and estimate that variable costs make up the remaining 8 percent of total production cost. Using this ratio and the annual generation information disclosed in FERC Form 1, we estimated an average annual total production cost in $/MWh for each year.

The next step was to analyze whether Georgia Power's unit-commitment decisions were economic or uneconomic. This analysis had to be conducted at the hourly level and was based on three variables: system lambda in $/MWh, net unit generation in MW, and production cost in $/MWh. Hourly system lambda was obtained from FERC 714. Gross hourly unit generation was available from the EPA's Clean Air Markets Division (CAMD) data portal. Because EPA CAMD reports gross generation and we needed to use net generation, we developed a monthly ratio of gross-to-net generation by comparing the monthly generation totals from EPA CAMD and EIA 923. This ratio varies by month but generally falls between 85–90 percent. The applicable monthly gross-to-net ratio was applied to each hour of EPA CAMD generation, and the resulting adjustment was used as hourly generation for each unit in our dataset. Finally, we applied the annual average cost of production for each hour of the year.

Once the hourly system lambda, hourly net generation, and hourly production cost datasets were in place, we compared the system lambda to the production cost for each hour from 2017 through 2020. Hours when the production cost was higher than system lambda indicate an hour where operating the coal plant was more expensive than procuring electricity from other sources. Conversely, hours when the production cost was lower than system lambda indicate that the coal unit was committed economically.

However, we wanted to assess the total value or the total excess cost of Georgia Power's coal fleet. Because coal units have long startup times, it is possible that they can be uneconomic for more hours than they are economic and still provide value overall. To estimate the total value or total excess cost of the units, we multiplied hourly net generation by the delta between the system lambda and the calculated production cost. We calculated these results on an hourly basis and could then combine them to check the performance of each power plant on a daily, weekly, monthly, or annual basis.

Unit-commitment analysis requirements

The analysis that underlies this report examined the difference between each unit's production cost and the system lambda for each hour during the period from 2017 to 2020. This sum total of all of these hours represents the total variable, excess costs incurred by Georgia Power and paid for by customers. We used this as a proxy to represent the excess costs incurred based on the company's uneconomic commitment practices. We did this both because this was the most accurate analysis we could do based on public data, and because it is not possible that the company would incur this magnitude of losses if it was both (1) accurately representing each unit's full production cost in its unit-commitment process; and (2) making daily economic commitment decisions.

For the Commission to actually review the prudence of the company's daily unit-commitment decisions, it would need to calculate the precise excess costs based on uneconomic commitment practices. To do so, Georgia Power would need to supply two sets of unit cost and system load data: (1) data on the company's projections at the time it made each daily commitment decision, and (2) data that shows what actually happened on its system. Because Georgia Power's system is jointly dispatched with the rest of the Southern Company's system, this data would need to be provided for all units on the Southern Company's system.

In the first category, the company would need to provide each unit's projected variable costs, projected output for each unit, and projected system load. Based on this set of data, the Commission can determine whether there were periods of time, or specific "events," when the company was projecting that a unit would cost more to operate than other units available (inclusive of both variable costs and startup costs), yet still opted to bring or keep that unit online. For each of those "events," the total cost projected from uneconomic commitment can be calculated as the difference between the cost to operate the unit and the cost of operating the lower-cost alternatives that were available, net of startup costs.

Then, to calculate the total costs actually incurred and passed on to ratepayers during each of these "events," the Commission would need data on what actually happened. This includes (1) detailed hourly cost data for each unit on the company's system; (2) MWh output from each unit in each hour; and (3) total system load in each hour. From this data, the Commission can calculate the actual excess costs that were incurred during each period when the company both projected a unit would incur excess costs from operating, yet still opted to operate that unit (once again, net of startup costs).We were unable to conduct such analysis because we only have annual average cost data for each unit, and we had no information on what costs the company projected for each unit at the time it made each unit-commitment decision. However, such analysis can easily be carried out if the company provides the necessary data outlined above. Without such data, it is possible to evaluate the excess variable costs incurred by the company, but not to thoroughly scrutinize the commitment decisions that the company made.

Appendix C. Additional Result Tables

Monthly value/excess cost by unit, including January 2018

		Net Generation (MWh)					Total Value/Excess Cost ($Millions)				
Year	**Month**	Bowen	Hammond	McIntosh	Scherer	Wansley	Bowen	Hammond	McIntosh	Scherer	Wansley
2017	1	1,199,865	16,107	0	246,760	224,420	($11.4)	($0.1)	$0.0	($0.7)	($0.2)
2017	2	891,641	0	0	127,583	0	($11.7)	$0.0	$0.0	($1.0)	$0.0
2017	3	779,048	0	0	297,482	269,707	($3.7)	$0.0	$0.0	($0.0)	$0.1
2017	4	1,529,236	0	0	239,229	188,147	($10.7)	$0.0	$0.0	($0.3)	($0.6)
2017	5	1,475,737	34,223	0	288,599	328,407	($12.8)	($0.6)	$0.0	($0.9)	($1.4)
2017	6	1,495,022	0	0	301,782	456,752	($13.4)	$0.0	$0.0	($1.1)	($2.6)
2017	7	1,227,660	135,490	1,015	383,430	568,335	($8.0)	($2.0)	($0.1)	($0.0)	($0.9)
2017	8	1,346,801	225,204	25,232	382,227	227,678	($8.2)	($3.5)	($2.0)	($0.2)	($0.3)
2017	9	1,129,917	97,527	0	282,408	506,702	($8.1)	($1.5)	$0.0	($0.3)	($1.5)
2017	10	1,013,532	0	0	260,508	379,822	($8.2)	$0.0	$0.0	($0.7)	($1.8)
2017	11	793,839	0	0	219,281	87,253	($7.4)	$0.0	$0.0	($0.9)	($0.7)
2017	12	1,036,860	2,334	830	221,143	482,548	($10.1)	($0.0)	($0.1)	($1.0)	($2.4)
2018	1	1,662,642	118,326	20,386	293,986	658,674	$107.6	$12.9	$2.4	$22.9	$56.6
2018	2	626,269	0	0	187,915	53,056	($8.9)	$0.0	$0.0	($1.5)	($0.6)
2018	3	927,334	0	0	175,209	0	($12.8)	$0.0	$0.0	($1.3)	$0.0
2018	4	587,683	0	0	203,162	0	($6.9)	$0.0	$0.0	($0.9)	$0.0
2018	5	889,286	0	0	246,326	314,234	($6.1)	$0.0	$0.0	($0.0)	($2.0)
2018	6	1,154,775	0	0	334,131	634,895	($7.9)	$0.0	$0.0	$0.2	($3.8)
2018	7	1,251,864	0	0	390,639	99,695	($8.0)	$0.0	$0.0	$0.4	($0.7)
2018	8	1,351,245	0	9,140	397,548	87,777	($6.2)	$0.0	($0.6)	$1.2	($0.4)
2018	9	1,389,797	49,642	957	332,869	500,935	($2.8)	($0.9)	($0.0)	$1.5	($0.3)
2018	10	1,213,508	32,260	0	290,613	330,246	($3.2)	($0.5)	$0.0	$1.0	$0.3
2018	11	1,300,411	0	0	378,396	74,582	($3.6)	$0.0	$0.0	$1.5	($0.2)
2018	12	1,228,105	0	0	305,108	41,510	$2.4	$0.0	$0.0	$1.7	$0.8
2019	1	758,482	4,137	0	244,731	158,306	($5.2)	($0.1)	$0.0	($1.6)	($2.4)
2019	2	379,100	98,744	21,019	139,504	10,378	($4.0)	($3.4)	($0.8)	($1.4)	($0.2)
2019	3	465,164	12,282	0	217,683	66,986	($2.8)	($0.4)	Retired	($1.3)	($0.8)
2019	4	703,000	0	0	228,492	15,095	($5.1)	Retired	Retired	($1.4)	($0.2)
2019	5	1,077,198	0	0	338,017	403,287	($4.3)	Retired	Retired	($0.8)	($4.3)
2019	6	1,239,173	0	0	275,446	203,546	($8.8)	Retired	Retired	($1.6)	($2.7)
2019	7	1,505,693	0	0	335,101	201,789	($7.3)	Retired	Retired	($1.1)	($2.1)
2019	8	1,305,861	0	0	273,974	202,247	($8.3)	Retired	Retired	($1.6)	($2.9)
2019	9	1,399,340	0	0	236,315	446,899	($4.6)	Retired	Retired	($0.5)	($4.6)
2019	10	528,527	0	0	182,118	0	($3.0)	Retired	Retired	($1.2)	$0.0
2019	11	682,319	0	0	174,642	67,894	($5.2)	Retired	Retired	($0.9)	($0.3)
2019	12	919,005	0	0	124,862	28,792	($11.2)	Retired	Retired	($1.5)	($0.5)
2020	1	214,658	0	0	56,771	0	($2.7)	Retired	Retired	($1.4)	$0.0
2020	2	238,903	0	0	41,016	0	($3.8)	Retired	Retired	($1.1)	$0.0
2020	3	345,595	0	0	55,583	0	($5.7)	Retired	Retired	($1.5)	$0.0
2020	4	325,186	0	0	27,038	0	($6.0)	Retired	Retired	($0.8)	$0.0
2020	5	190,880	0	0	68,780	0	($3.3)	Retired	Retired	($1.9)	$0.0
2020	6	323,030	0	0	97,543	0	($4.9)	Retired	Retired	($2.4)	$0.0
2020	7	997,537	0	0	231,329	98,472	($11.5)	Retired	Retired	($5.0)	($3.2)
2020	8	1,610,873	0	0	243,456	0	($13.2)	Retired	Retired	($4.4)	$0.0
2020	9	990,494	0	0	188,176	0	($8.0)	Retired	Retired	($3.7)	$0.0
2020	10	471,589	0	0	79,126	0	($2.4)	Retired	Retired	($1.6)	$0.0
2020	11	837,924	0	0	68,246	0	($7.6)	Retired	Retired	($1.3)	$0.0
2020	12	1,393,527	0	0	133,920	94,032	($9.6)	Retired	Retired	($2.3)	($2.8)

Sources: Calculated from FERC Form 1, FERC 714, EIA-923, EPA CAMD.