Comparing the Impacts of Different Spinning Reserve Targets in Electric Power Systems with Increased Penetration of Renewable Energy

Master's Project Report

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EXECUTIVE SUMMARY

With an increasing demand for electricity and unprecedented penetration of renewable sources of energy on the grid, power systems are facing growing challenges to maintain system reliability and limit rising costs. Optimizing the practices used to set operational reserve targets, which include spinning and non-spinning reserves (SR & NSR) can help in this regard. SR are provided by generating resources that are online and running and have additional unused capacity that allow the system to modify power output to overcome unexpected generator outages or forecasting errors without having to shed any load. NSRs are reserves provided by power generators that are offline but have a high ramp-up rate and hence can be called upon when desired. Examples of generators capable of providing NSRs are fast-start units such as NG-CT plants. Power system operators schedule electricity units so that predetermined reserve targets are met. These reserve requirements can be defined as a % of load or as a constant MW value for all hours, with any specification of the allowed partitioning of these into spinning and non-spinning reserves. <u>The optimal split between spinning and non-spinning resources is the focus of analysis for this study</u>. The overarching research question for this analysis is "What is the best partition between spinning and non-spinning reserves such that a) Overall system costs are minimized, b) Reliability is maintained or improved, and c) Emissions are maintained or decreased". The production cost model developed by GRACE (also called the Current Practice Model - CPM) was used to simulate hourly system operations for the DEC/DEP system. A brief overview of CPM is given below –

<u>Brief Overview of the CPM:</u> The CPM is composed of 3 Unit-Commitment models namely First UC, Balancing UC, and Second UC often abbreviated as FUC, BUC, and SUC. In FUC, plants are <u>scheduled</u> based on inputs of initial conditions, outages & deratings, and a <u>week ahead forecast</u> of PV and demand data. It runs at the beginning of the day. SUC is very similar to FUC which is run later in the day, updating for outages, deratings, and imports of NG and other fuels. BUC, also known as real-time UC, is where all plants are dispatched to meet the real-time demand at the lowest cost after accounting for real-time PV production. This BUC is run for all hours.

The CPM model was run for the month of February for the 2019 calendar year and for a theoretical 2030 system that is significantly more de-carbonized than the 2019 system. February was chosen over other months because it had the largest difference between actual and forecasted electricity consumption. The datasets comprising generator parameters & costs, electricity consumption, and solar PV data for the 2019 calendar year were provided by Duke Energy. The Carolinas Carbon Plan was used to modify the datasets to simulate system operations for the theoretical 2030 system. For our analysis, the maximum proportion of NSR of the total operational reserves is varied from 0% to 100% with an increment of 20%. A 27% NSR cap was set as a baseline. For the analysis, NSR caps were enforced only for the day-ahead UC models and not for real-time UC models (BUC). This is because day-ahead UC models are

forward-looking in nature and if reserve caps are not enforced, the solution would be sub-optimal since the model would be relying on NSR to ramp up and meet the load. The reason why caps aren't enforced in the BUC is that NSRs are always available in real-time. Post-processing was done to better understand the critical system parameters including system costs, GHG emissions, and reliability which is quantified in terms of demand curtailment in our analysis.

In the 2019 system, relative to the baseline of 27% NSR, it was observed that 20% NSR had the greatest percent decrease in total system costs. On the reliability front, it was observed that there wasn't any significant demand curtailment for any of the NSR caps, meaning, the system was reliable regardless of partitions set between SR and NSR. On the emissions front, once again, relative to the baseline of 27% NSR, 20% NSR had the greatest percent decrease while 40% NSR had the greatest percent increase in CO_2 emissions. For the 2030 system, relative to the baseline, it was observed that 0% NSR had the greatest percent decrease in total system costs. The overall cost for the 2030 system was 3-5% higher than the 2019 system, depending on the NSR cap. The key takeaway with regard to costs was that as the grid becomes increasingly decarbonized, a more stringent SR requirement does a better job of optimizing operations. On the reliability front, there was a significant demand curtailment (13-14% of hours for all NSR caps). On the emissions front, 60% NSR had the greatest percent decrease while 40% NSR had the greatest percent increase in CO_2 emissions. Overall, there was no clear pattern that emerged in regard to emissions and the NSR cap that was set.

Although our analysis can be used to better understand the effects of different partitions between SR and NSR, there are some limitations that could be addressed in a future study. First, simulations were performed only for the month of February. Hence, it is hard to thoroughly understand the system impacts without running the model for the entire year. Second, the 2030 system was modeled by making several assumptions based on the Carolinas Carbon Plan, which could be updated for accuracy. Finally, our analysis focused on setting reserves only in the day ahead and not in real-time. Investigating an approach to setting spinning reserves in real-time on an hourly basis could be explored.

ACKNOWLEDGEMENT

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ABSTRACT

This paper explores the effects of different spinning reserve requirements for electric power systems and examines the DEC & DEP balancing authority in the Carolinas. A deterministic production cost model was used to simulate power system operations of a) 2019 electricity generation fleet and b) a theoretical decarbonized 2030 fleet. The model was run for the month of February for both cases and spinning reserve practices were evaluated through the lens of system cost, system reliability, and CO_2 emissions. A 27% non-spinning reserve cap was chosen as the baseline for the analysis. Relative to the baseline, a 20% non-spinning reserve cap showed the greatest percent decrease in system costs for 2019, and maintained system reliability, while slightly increasing emissions. A 0% non-spinning reserve cap showed the greatest percent decrease in system costs for the theoretical 2030 simulation and improved reliability from the baseline, while maintaining the level of CO_2 emissions.

1. Introduction

Just in the past few years, there have been a variety of examples that highlight the vulnerability and the stress that the electricity grid in the United States is under. In February of 2021, during a major winter storm in Texas, their power system faced near collapse and left millions without power for multiple days. Just this past December (2022), another cold spell swept across the country and put enormous stress on various power systems. Utilities including Duke Energy Carolinas, Duke Energy Progress and Tennessee Valley Authority were all forced to begin rolling blackouts within their territories due to the demand for electricity exceeding the supply that they could provide. As intermittent resources begin to make up a greater and greater share of the energy generation portfolio in many economies, it is critical for electric power systems to explore mechanisms that ensure they are able to maintain reliability for their customers in a cost-effective manner.

Spinning reserves are used in electric power systems primarily to ensure that power generators have head and floor room to modify their power output to help the system overcome any unexpected generator outages or significant load or solar and wind forecasting errors, without having to shed any load (Amjady et al 2010). Spinning reserves are generally defined as the reserve capacity that is provided by generating resources that are online and running and have additional unused capacity which can be activated, usually within a 10-minute time span, on the decision of the system operator. The specific requirements to qualify as a spinning reserve can vary among balancing areas (see Appendix). Regardless of the specific definition, having spinning reserves is critical to maintaining the security and quality of the supply of electricity. Controlling and maintaining the frequency of the electricity grid requires that a certain amount of active power be kept in reserve, so that operators have the capability to re-establish the balance between load and generation at all times (Rebours et al 2005).

In terms of setting reserve targets, there are two distinct considerations that are important. First, what level to set operating reserves at in terms of megawatts and then secondly, how to partition reserves between spinning and non-spinning reserves. This paper focuses on the partitioning between spinning and non-spinning reserves. There are various methods that are commonly used to set spinning reserve levels in electric power systems. Historically, the two most common methods are either to set a specific target value of spinning reserves that must be met, often based on the size of the largest unit that is currently in the system (known as the n-1 approach), or to set the spinning reserve level as a percentage of the overall demand (Amjady et al 2010, Rebours et al 2005). Another method consists of setting reserve targets equal to a percentage of load, plus a percentage of variable energy resources, that is calculated based on forecast uncertainty (Krad et al 2015). Finally, an additional method that has been proposed adjusts reserve targets in order to satisfy a constraint limiting the loss of load probability (Pengpeng et al 2016). This theoretical loss of load probability constraint would be embedded within an energy system's unit commitment model and would adjust the spinning reserve levels within the system, if needed, in order to satisfy the constraint.

When considering the level of spinning reserves to set, there is a tension between affordability and reliability. In general, the larger the level of spinning reserves, and the wider the array of the distribution of spinning reserves (both of which improve reliability), the higher the operational costs of the system will be (Pengpeng et al 2016). This is because if there is a larger distribution of spinning reserves that is required, the reserves will have to be distributed more evenly across a larger number of units, as opposed to being concentrated in a smaller number of lower production cost units.

This paper's exploration and comparison of targets for setting spinning reserve requirements in electric power systems uses a deterministic model developed by the GRACE project (ARPA-E funded project) to simulate electric power system operations. The model is optimizing through system cost minimization and allows for adjustments to be made to the spinning reserve requirement. The impacts of altering the spinning reserve requirement as it relates to system reliability as well as greenhouse gas emissions are also observed from the model outputs. While much of the literature discussed here goes into detail describing the various practices for setting spinning reserve requirements that currently exist, there is not much existing research looking into a comparison of these different methods. This analysis explores a number of strategies for maintaining spinning reserves within Duke Energy's system, with a particular focus on how best to partition spinning vs non-spinning reserves.

2. Methods and Data

A Production-Cost model developed by the GRACE Project (an ARPA-E funded project that is focused on developing a risk-aware energy management system under deep penetration of wind and solar), is used to simulate the electricity generation and consumption for Duke Energy Carolinas and Duke Energy Progress, the two major electric utilities in North & South Carolina, on an hourly basis (GRACE 2023). GRACE's objective is to develop an approach for the scheduling and dispatch of generators that - 1. Minimizes operating costs, 2. Maintains or improves reliability, 3. Maintains or improves the utilization of low carbon resources, and 4. Quantifies the impacts of grid resources on system risk.

This study will use the production cost model to analyze spinning reserve practices from two different perspectives. First, the study will simulate system operations based on inputs from the 2019 calendar year with the goal of determining what would have been the optimal spinning reserve practice for the DEP & DEC system during that year. Then, the study will use inferences from Duke Energy's Carolinas Carbon Plan to model a futuristic 2030 energy system that has gone through significant decarbonization, to try and determine whether the optimal spinning reserve practice will need to change as intermittent renewables make up a greater share of the energy generation portfolio.

2.1 The DEP & DEC System

Combined, the two companies serve 4.2 million customers over a 56,000 square mile area, in both North Carolina and South Carolina and have an electricity generation capacity of greater than 30,000 megawatts (Carolinas Carbon Plan 2022). See a full breakdown of DEC and DEP generation portfolios in the Appendix.

2.2 Generator Parameters and Costs Provided By Duke Energy (2019)

The generator parameter and operational cost data that was used as inputs for the production-cost model was provided by Duke Energy and was based on their generation portfolio from the 2019 calendar year. 2019 was selected as the initial year of analysis because it is the most recent year from which electricity demand data is available that was not impacted by the Covid-19 pandemic. The generation portfolio consists of nuclear power (which is assumed to be nearly constant throughout the year, other than some periods of derating to account for required maintenance), solar PV generation, hydro power generation, battery storage, and finally 64 slow-start natural gas or coal-fired generators and 80 fast-start or peaker power generating units. These dispatchable generators are being optimized by the production-cost model to meet electricity demand on an hourly basis. All relevant generator parameter data has been provided by Duke Energy including generating unit names, the balancing area in which they reside, the type of unit, their minimum and maximum power outputs, all operating costs including start up and shut down costs, ramping limits, minimum uptime and downtime requirements, ON/OFF status, and plant derating.

2.3 Electricity Demand Data (2019)

The electricity demand data that was provided by Duke Energy, for both DEC and DEP zones, was also from the calendar year 2019 and comes in three parts: day-ahead hourly forecasted electricity demand with a one-week horizon, an update to the hourly forecasted electricity demand (in this case is the exact same as the original forecast), and finally the actual hourly electricity demand. The forecasted data used in this analysis of the 2019 year, were the real forecasts used by Duke Energy, and the actual electricity demand was the actual electricity consumption of DEC and DEP customers in 2019, without accounting for electricity imports and exports from/to neighboring service territories. The forecasted electricity demand was used as input data for the first unit commitment run, the update to the forecasted electricity demand was used as input data for the second unit commitment run and the real electricity demand was used as input data for the balancing unit commitment runs. Further details of the unit commitment runs are explained in section 2.5. Once again, data from 2019 was used because it was the most recent full calendar year in which data is both readily available and not impacted by changing electricity consumption patterns that were caused by the Covid-19 pandemic.

2.4 Solar PV Data (2019)

Similar to the electricity demand data, an initial day-ahead hourly forecast of solar PV generation with a one-week horizon, an updated hourly forecast of solar PV generation (again, for this analysis, the updated forecast is the exact same as the original forecast), and the real-time actual hourly solar PV generation for DEP and DEC in 2019 were used as model inputs for this analysis.

2.5 GRACE's Representation of Duke Energy's Energy Management System

GRACE's Current Practice Model is a method of representing Duke Energy's Energy Management System (EMS). This deterministic model is run with static reserve requirements and is useful to show the comparative benefits of new approaches. The schematic is shown in **Figure 1** in the Appendix. Based on initial conditions (ON/OFF status of generating units and their current level of electricity generation), unit outage & derating status (availability of plants and their deratings), demand and PV forecasts, the first unit commitment (FUC) model is run from hours 7 to 168 (creating an initial plan for the entire week ahead). This is a plan for the dispatch of power plants. In hour 7, based on the actual electricity demand for the hour, PV actuals, and updated deratings & outage status of the plants, a model to adapt to this new reality, referred to as the balancing unit commitment (BUC) model is run. The supply and demand are met on an hourly basis through the balancing unit commitment model, without looking into the future. This is repeated until hour 17. At hour 17 (5 PM), based on the updated outage & derating status, updated demand and PV forecasts, a second unit commitment (SUC) model for hours 18 to 168 is run. The SUC is essentially identical to the FUC, except that the SUC abides by the constraints that arise from the limited quantity of natural gas purchased based on the FUC results. The units are optimized from hours 18 to 168 and an updated plan for the week ahead is created. Based on the PV actuals and real-time demand, the BUC is run from hour 18 to hour 30. Then as a new day begins, the FUC is run and this whole process repeats once again.

2.6 Assumptions for the 2030 system

In order to model DEP & DEC's future energy system for the year 2030, the input structure that was used for 2019 simulation was used once again, while the actual input values were adjusted to account for changes to the system that may occur by the year 2030. Portfolio 1 from the Carolinas Carbon Plan was used to inform these changes. The following assumptions were made to model the 2030 system:

- Forecasted energy sales (hourly electricity demand) would grow by 0.7% per year for the DEC system and 0.4% per year for the DEP system. These growth percentages were based on projections from the Carolinas Carbon Plan (Table F-16 and Table F-17). The same hourly demand from 2019 was used, only the values increased, based on these growth rates.
- Portfolio 1 of the Carolinas Carbon Plan projects an additional 2100 MW of battery storage to be incorporated into the energy system by 2030. In 2019, there were 8 utility scale batteries in the system. The additional 2100 MW was split evenly and added to each of the 8 existing batteries' capacity.
- Portfolio 1 of the carbon plan calls for an additional 5400 MW of solar capacity to be added to the system by 2030. This would increase the capacity of solar generation in the system by a factor of 2.358 from 2019

levels. The hourly solar generation from 2019 was multiplied by this factor for the 2030 system.

- The carbon plan also projects that both onshore and offshore wind will be added to the system. Due to model limitations, incorporating wind generation into the current practice model was not feasible. Therefore, for this analysis, all investments (in dollars) that would have gone towards creating wind generation was assumed to be put towards solar and storage. CAPEX costs for solar and battery were taken from a conservative outlook from Open Energy Data Initiative's Annual Technology Baseline Outlook. The CAPEX for solar was 1150 $/kW Dc while it was 2650 $//kW Dc for battery storage. This added an additional 2378 MW of solar capacity and 1190 MW of storage capacity to the system. These additions were added to solar and storage respectively, in the same manner discussed in the previous two bullet points.
- Fuel prices were assumed to have increased by a factor of 1.5 for natural gas and oil and by 1.25 for coal from the year 2019 to the year 2030.
- Coal plant retirements were outlined in the Carolinas Carbon Plan. The maximum capacity for the following units were reduced to zero for the 2030 system: Allen (units 1 and 5), Cliffside (unit 5), Marshall (units 1 and 2), Mayo (unit 1) and Roxboro (units 1-4).
- Based on the carbon plan, 1.1 additional GW of CT generation are to be added to the system by 2030. To represent this generation capacity increase, 13.58 MW of capacity were added to each of the existing 81 CT plants from the 2019 system.
- 2.4 additional GW of CC generation are to be added to the system by 2030. To represent this capacity increase, 218.18 MW of capacity were added to each of the existing 11 CC plants from the 2019 system.

2.7 Analysis Process

The initial goal of this analysis was to determine what the optimal spinning reserve requirement would have been for DEC and DEP's energy system in the year 2019. The first stage was to try and determine an optimal partition between spinning and non-spinning reserves. Having an optimal partition of spinning reserves to non-spinning reserves, is most important when there is a significant difference between the electricity demand that was forecasted and the electricity demand that is observed in the real-time. If there is a discrepancy between what was expected and what actually occurs, it may be necessary for spinning reserves to quickly ramp up or down to accommodate for the change in demand. It was observed that the largest differences between forecasted electricity consumption and actual electricity consumption for DEC and DEP during 2019 occurred during the month of February. For this reason, the production cost model was used to simulate operations of the DEC and DEP system for the month of February in the year 2019 at different partitions of spinning reserves and non-spinning reserves. The non-spinning reserve cap (a constraint that limited the percentage of scheduled reserves that could be non-spinning reserves) was modified for these simulations, ranging from 0 percent to 100 percent, at intervals of 20 percent. A non-spinning reserve cap of 27 percent was used as a baseline to measure all results against.

Once the best performing partition had been selected, the study examined whether these results remained consistent in a future grid that is significantly more decarbonized. The analysis process for determining the optimal spinning reserve practice remained essentially the same, with only the inputs being updated. Otherwise, the same current practice model was used to simulate system operations for the month of February (2030) at the various non-spinning reserve caps, that once again, ranged from 0 percent to 100 percent, at intervals of 20 percent, to be compared against a baseline with a non-spinning reserve cap of 27 percent.

2.8 Model Outputs and Post Processing

Upon the completion of runs with the production-cost model, post-processing analysis was conducted in order to further understand and visualize the results of the model outputs. The post-processing analysis was used to compute important figures that describe the performance of the system such as total system costs, the system average levelized cost of electricity, greenhouse gas emissions from electricity generation, and reliability information, such as whether or not any demand curtailment was required.

3. Results & Discussion

3.1 CPM Results for February 2019

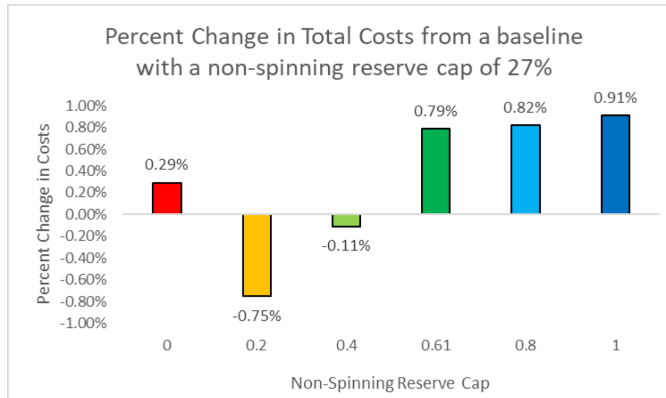
The production cost model was run from day 32 (Feb 1) to day 60 (Mar 1) for the various spinning reserve levels, using the available 2019 data and the updated inputs meant to replicate a future 2030 system. The results were recorded and are discussed below.

3.2 System Costs

3.2.1 2019 System Costs

Summarized results of the total system costs from the initial model runs can be seen in **Figure 2**:

Figure 2: % change in February 2019's system cost from baseline



These results reflect the percent change in total system costs for the different spinning reserve caps that were tested, in comparison to a baseline where the non-spinning reserve cap was set at 27 percent. The maximum percent increase in system costs were observed for a non-spinning reserve cap of 100% and the greatest percent decrease in system costs were observed for a non-spinning reserve cap of 20%.

3.2.1.1 Inferences on System Costs and Reserve Partitioning (2019 system)

With minor differences (less than 1%) in total system costs, regardless of the spinning reserve requirement, it was important to explore whether the spinning reserve requirement was actually influencing generator dispatch within the model. To investigate further, the spinning and non-spinning reserves were computed for each hour of February 2019, according to the following formula: SR = Min(RampUpRate, MaxCapacity * Rating - Current

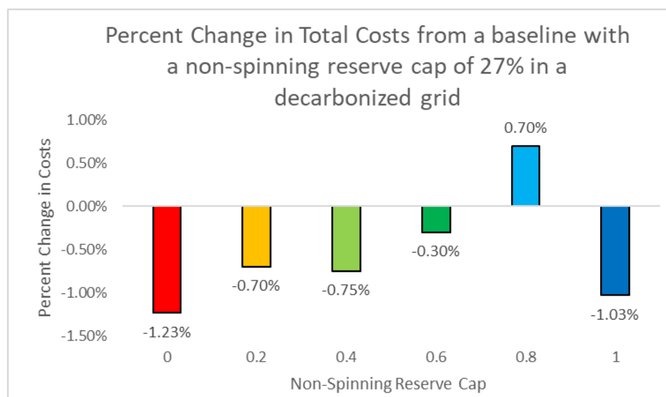
Power Output) * ON/OFF status. NSR = Min(StartUpRampRate, MaxCapacity * Rating), IF(ON/OFF status = OFF). At first glance, it appeared that the non-spinning reserve cap was being exceeded. However, it only appears this way when observing all *available* reserves. For *scheduled* reserves, the constraint was being enforced correctly. Even with available reserves, the non-spinning reserve constraint in most cases caused a higher percentage of available reserves to be spinning reserves, when the constraint was stricter (lower). In some cases, despite the increase in the allowed percentage of non-spinning reserves, the partition between spinning and non-spinning reserves had no significant bearing on the total cost of electricity. This could be explained by a couple of reasons - a) It actually doesn't cost more to deploy non-spinning reserves than to schedule spinning reserves (or) b) The scheduled spinning reserves are more than enough to meet real-time needs so non-spinning reserves aren't needed and hence they are not deployed and no real-time cost is incurred. It is also worth noting that this system has significant energy storage capacity which is a source of reserves available at all times.

The following observations could be made to explain our results as it relates to the partition of available reserves (spinning vs non-spinning). For a NSR cap = 0, all scheduled reserves are spinning and this could actually have either higher or lower costs.In the day-ahead unit commitment, for a NSR cap > 0, a higher cost could be incurred because we may have to turn on plants that we would not have started up otherwise. In the real time UC, however, for a NSR cap > 0, the costs could be higher or lower. They would be higher if the spinning reserves are in abundance. It will be lower if the spinning reserves are all needed, unless start-up costs for non-spinning reserves are comparably low, such as dispatching storage.

It is important to note that the reserve caps were set only for the FUCR and SUCR. In real time, there is no constraint on the non-spinning reserve cap. This is adequate since non-spinning reserves are always available. The cap on non-spinning reserves are included in the FUCR and SUCR as a forward-looking approach since if there was no non-spinning reserve cap, the model may always count on the non-spinning reserves, and the solution would be sub-optimal if they were more expensive to deploy due to the added start-up costs, which would not be present with spinning reserves.

3.2.2. 2030 System Costs

Figure 3: % change in February 2030's system cost from the baseline



These results reflect the percent change in total system costs for the different spinning reserve caps that were tested, in comparison to a baseline where the non-spinning reserve cap was set at 27 percent, for a hypothetical 2030 energy system. The maximum percent increase in system costs was observed for a non-spinning reserve cap of 80% and the greatest percent decrease in system costs was observed for a non-spinning reserve cap of 0%. This differs from the 2019 results, where the greatest decrease in system costs was observed with a non-spinning reserve cap of 20%. For 2030, there appears to be a general increase in costs as the non-spinning reserve cap increased, aside from an outlier with the non-spinning reserve cap at 100%. The results are consistent with expectation up until passing the 80% non-spinning reserve cap.

From 2019 to 2030, total system costs for the month of February increased by roughly 3 to 5 percent, depending on the non-spinning reserve cap. While not an enormous percentage increase, when total system costs for a month are in excess of $100 million, small percentage increases can quickly become costly. This increase in cost is likely due to a greater reliance on expensive natural gas peaker plants that are used more frequently to meet demand.

3.2.2.1 Inferences on System Costs and Reserve Partitioning (2030 system)

As mentioned, a non-spinning reserve cap of 0% led to the greatest reduction in total system costs relative to the baseline for the 2030 system simulations. As was the case for 2019, in 2030 if the spinning reserves end up being utilized by the system in order to meet load, the expected outcome would be a reduction in costs, as these reserves did not end up running unnecessarily (in hindsight). It is of course necessary to schedule reserves because there is not perfect foresight for electricity demand, however if there was, reserves would not be necessary. For this reason, actually using spinning reserves that are scheduled, will reduce system costs. With a non-spinning reserve cap of 0%, all scheduled reserves must be spinning reserves and in a more decarbonized electricity grid, it is more likely that they will need to be used to meet demand.

3.3 Reliability

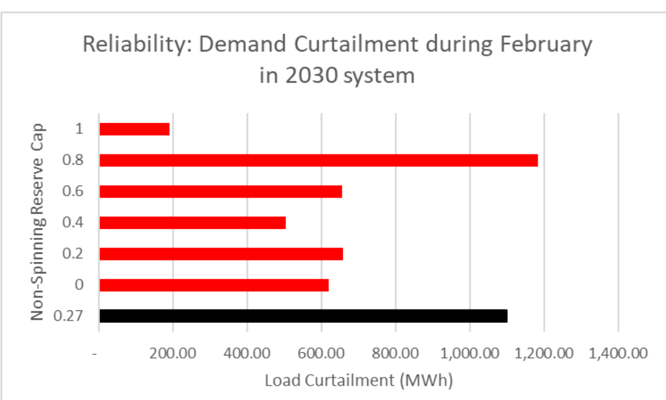
3.3.1 2019 Reliability

When analyzing spinning reserve requirements, the goal is to reduce total system costs while maintaining or improving reliability and maintaining or decreasing system emissions. For each of the various non-spinning reserve caps that were modeled for the month of February in 2019, there was not any case that saw a significant reduction in system reliability. For this analysis, system reliability was measured or quantified with demand curtailment and over-generation. In the model, demand curtailment would occur if there was ever insufficient generation to meet the electricity demand within a given hour. Over-generation would occur if there was ever excess generation in comparison to the electricity demand within a given hour. The model was disincentivized from ever relying on demand curtailment or over-generation due to an associated hefty penalty cost that was included in the model's objective function. No non-spinning reserve cap saw a monthly demand curtailment of greater than 6 MWh, which in an entire month for a system as large as DEC and DEP, is insignificant. These results suggest that regardless of the spinning reserve requirement being enforced, reliability standards would not have been impacted in a significant manner for the 2019 year. In terms of total system costs, it was observed that the non-spinning reserve cap of 20%, led to the greatest reduction in total costs for the month of February, relative to the baseline. This non-spinning reserve cap was successfully able to achieve a reduction in total system costs while maintaining system reliability.

3.3.2 2030 Reliability

Once again, demand curtailment was used to assess system reliability. Unlike with the 2019 analysis, significant demand curtailment was observed for the 2030 simulations. This likely has to do with some non-realistic assumptions such as the lack of wind generation, lack of increased energy storage capacity, lack of imports and exports, plant generation status, etc. For this reason, it is probably less useful to consider the total amount of demand curtailment observed, and more useful to examine the difference between the amount of demand curtailment that took place for each of the non-spinning reserve caps. Load shedding during hour 1 of the month is not included because the model was not able to consider any plants that may have already been online and operating in the hours preceding the first hour of the month. The figure below displays the load shedding that took place for each of the caps in February 2030:

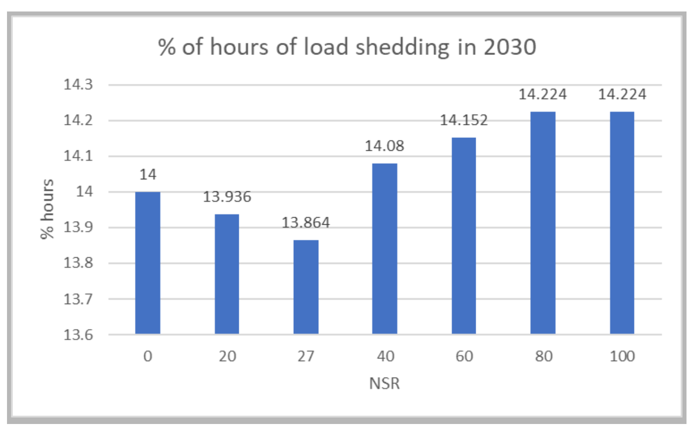
Figure 4: Total Load Shedding for month of February in 2030 System



The non-spinning reserve cap of 0%, which was observed to lead to the greatest reduction in total costs for the 2030 system, also had lower levels of load shedding relative to the baseline. While it is concerning that load shedding was necessary, a more thorough update of the model inputs would ideally solve this issue. The key is that system cost reductions were achieved while also improving the reliability relative to the baseline. It is interesting that the least amount of demand curtailment took place with a non-spinning reserve cap of 100%. Without a limit on what reserves needed to be spinning, the system was unconstrained to turn on fast start generators whenever necessary to try and meet load.

To get a better sense of load shedding across the different levels of non-spinning reserve caps, descriptive statistics were calculated. From the results, it was inferred that the maximum load shedding across all scenarios had the same magnitude and occurred at the starting hour of the month. This is because power plants were considered to be turned on at the starting hour. The model is "standalone" in nature - doesn't rely on the operating status of the plants prior to the first hour in February. The maximum load shedding also happened to be concentrated at the DEP region and the percent of hours of load shedding ranged from 13.86% to 14.22% corresponding to 27% and 100% NSR respectively (**Figure 5**).

Figure 5: % Hours of Load shedding in 2030

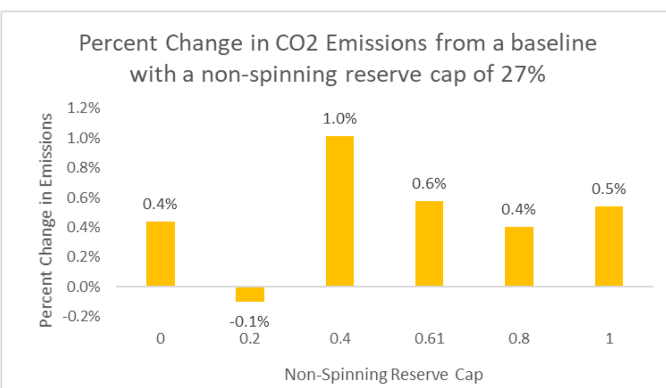


3.4 CO_2 Emissions

3.4.1 2019 CO2 Emissions

The monthly CO_2 emissions due to electricity generation were computed for each of the different model runs. The percentage change in emissions can be seen in **Figure 6**. The 27% NSR cap case was taken as a baseline for calculating the percentage change. From the plot, we can observe that the 40% non-spinning reserve cap recorded the highest percentage increase (1% increase) while the 20% non-spinning reserve cap recorded the greatest percentage decrease (decrease of 0.1%) of CO_2 emissions. There does not seem to be a clear trend in variation of emissions against the spinning reserve requirement, though any changes in emissions were minimal, regardless of the requirement level. Of all fuel types, coal plants have the highest CO_2 emissions rate. Perusing the output generation portfolio by fuel type for all the cases, coal plants have their maximum generation for a non-spinning reserve cap of 40%, which explains the level of emissions recorded for the 40% cap.

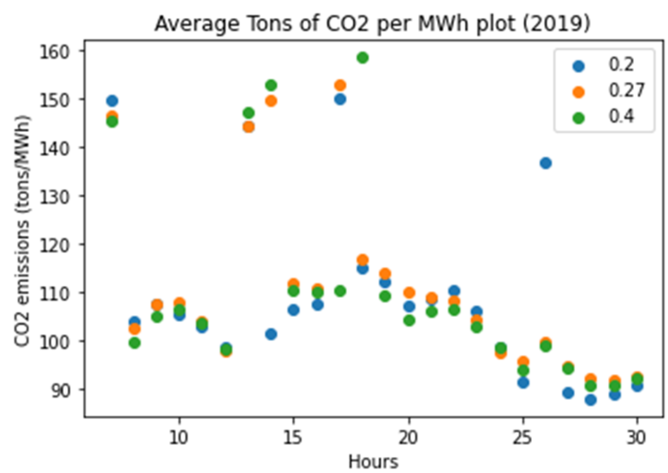
Figure 6: % change in CO_2 emissions (2019)



When optimizing for costs, it was noted that a non-spinning reserve cap of 20% performed the best in terms of minimizing total system costs. While achieving a 0.75% reduction in total costs for the month of February compared to the baseline, there was a 0.1% decrease in CO_2 emissions. While not enormous, it is still a noteworthy point of consideration. This spinning reserve scheduling practice was able to reduce costs without causing a subsequent increase in emissions.

The two non-spinning reserve caps that performed the best in terms of costs were the 20% cap and the 40% cap. The average hourly emissions rate per MWh for each hour of the day during the month of February for these two caps and the baseline case can be seen in **Figure 7**:

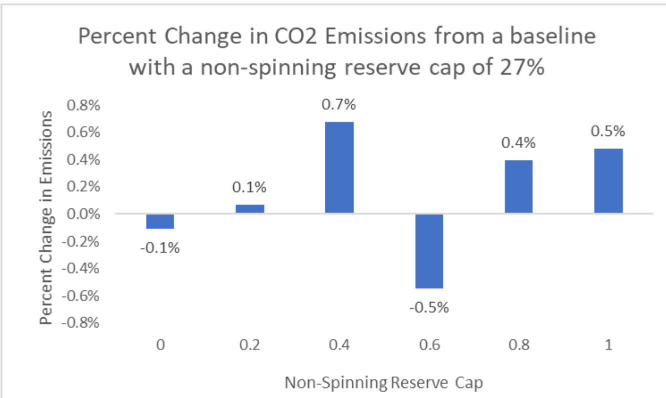
Figure 7: Average CO_2 Emissions Rate per MWh of generation for each hour of the day (2019)



3.4.2. 2030 CO_2 Emissions

The monthly CO2 emissions due to electricity generation were again computed for each of the different model runs for the 2030 case. The percentage change in emissions can be seen in **Figure 8**. From the plot, we can observe that, similar to the 2019 simulations, the 40% non-spinning reserve cap recorded the highest percentage increase (0.7% increase) in CO_2 emissions from the baseline. The 60% non-spinning reserve cap recorded the greatest percentage decrease (0.5% decrease) in CO_2 emissions. Again, there was no clear trend in the variation of emissions against the spinning reserve requirement, with only minimal variations being observed.

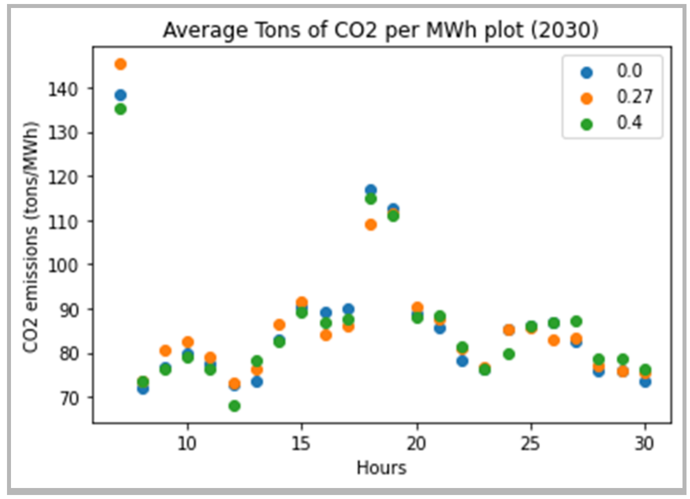
Figure 8: % change in CO_2 emissions (2030)



When optimizing for costs in the 2030 scenario, it was observed that the non-spinning reserve cap of 0% performed the best in terms of minimizing total system costs. This spinning reserve practice was able to achieve a 1.23% reduction in system costs, relative to the baseline, while also essentially maintaining the same level of CO_2 emissions.

The two non-spinning reserve caps that performed the best in terms of costs were the 0% cap and the 40% cap. The average hourly emissions rate per MWh for each hour of the day during the month of February for these two caps and the baseline case can be seen in **Figure 9**: Similar to load shedding, maximum CO_2 emissions were observed at the starting hour. This can be attributed to the fact that all generating units are starting/ramping up.

Figure 9: Average CO_2 Emissions Rate per MWh of generation for each hour of the day (2030)



3.5 Limitations of this work and future scope

Due to time constraints, and the length of time associated with running the production cost model, this analysis was only able to simulate DEP and DEC system operations in intervals of one month time periods. This was not ideal because, month to month, there can be significant variations in electricity consumption patterns as well as power plant availability. It is difficult to thoroughly understand system impacts of different spinning reserve requirements without simulating system operations for a full year. Inferences had to be extrapolated from monthly outputs for this analysis. Changing the spinning reserve requirement depending on the time of year could be a strategy for further optimizing reserve requirements. One could presume a less stringent reserve requirement would be more cost-effective in months of lower electricity consumption and or lower uncertainty. Adjusting the reserve requirement over the course of the year would be a great point for future analysis. Additionally, investigating an optimal approach to set spinning reserve requirements dynamically, on an hourly basis, as opposed to using the same targets for the whole day or month, could also be explored.

A more granular representation of potential power generation portfolios in a DEP & DEC's 2030 energy system would also be useful in order to truly understand how different spinning reserve requirements would impact system operations under increased renewables penetration. While this analysis can help to broadly understand the impacts of spinning reserve requirements in decarbonized energy grids, inferences on the future performance of Duke Energy's grid in the Carolinas cannot be accurately made. It was noted there was an increase in total system costs from 2019 to 2030 for all spinning reserve requirements that were analyzed. This likely was due to the increased reliance on expensive peaker plants that were needed to quickly ramp up and down to meet load. Once again however, it is difficult to make conclusive inferences on the 2030 system's costs due to the limitations of the power generation fleet represented and uncertainty on future forecast errors and power generation from renewables.

4. Conclusions

The current study dealt with exploration and comparison of targets for setting spinning reserve requirements in electric power systems using models developed by the GRACE project to simulate electric power system operations in the DEC/DEP zones for the month of February 2019 as well as a possible future power system in the year 2030. The following conclusions were drawn -

a) The system costs' rise was greatest for a non-spinning reserve cap of 100% while decreasing the most for a non-spinning reserve cap of 20% in the 2019 analysis. It was observed that a non-spinning reserve cap of 0% increases costs and a non-spinning reserve cap of 20% decreases them. It is important to acknowledge that perhaps the true optimal spinning reserve requirement for February 2019 is in between the two percentages. Higher costs result from either having an abundance of spinning reserves in real time or forecasting to turn on plants in the day ahead UC that might not be dispatched in real time. On the other hand, lower costs correspond to cases where spinning reserves are more often used, unless non-spinning reserves have lower start-up costs. For the 2030 system, the highest percent increase and percent decrease in system costs incurred when the non-spinning reserve cap was 80% and 0% respectively. Increasing the cap of non-spinning reserves had an increase in the percent change in costs but there was an anomaly when the cap was set at 100% where the system costs dropped below the baseline costs. A key takeaway with regards to costs was that for the 2019 system, it was evident that a moderately strict spinning reserve requirement was optimal. This means that it was useful to have spinning reserves make up a significant portion of all the scheduled reserves. However, there is a point where having all or nearly all scheduled reserves as spinning, was wasteful and unnecessary, as they were not needed. For the more decarbonized system, it was evident that the most stringent method for requiring spinning reserves ended up optimizing system costs. While the true optimal non-spinning reserve requirement may have been somewhere between 0 and 20 percent, it was clear that as the system became more decarbonized, and relied more on intermittent and non-dispatchable sources of electricity generation, it was better for the system to have all or nearly all of the scheduled reserves set as spinning reserves.

b) The system's reliability was quantified by demand curtailment and overgeneration. For none of the cases modeled (non-spinning reserve caps in 2019), was there any notable demand curtailment, demonstrating that the system was reliable enough with the 2019 generation portfolio of the DEC/DEP system to maintain acceptable reliability regardless of the spinning reserve requirement. The overall reliability for the 2030 system - again quantified by load shedding - decreased compared to the 2019 system. There could be several reasons explaining this such as insufficient additions of power generation capacity to replace the retired power plants, for example. The reliability results are highly dependent on the assumptions made regarding the new generation. It is likely that a more accurate representation of DEP/DEC's electricity generating portfolio for 2030 would have improved the level of reliability.

c) The percent change in CO_2 emissions was again computed relative to the baseline non-spinning reserve cap of 27%. It was observed that a non-spinning reserve requirement of 40% had the highest percentage increase (1.0% increase) in CO_2 emissions, while a non-spinning reserve requirement of 20% had the only observed percentage decrease (decrease of 0.1%) in CO_2 emissions for the 2019 analysis. The variability of changes in emissions due to a revolving spinning reserve requirement, did not display a clear pattern. For some non-spinning reserve levels, particularly the non-spinning reserve cap of 40%, the model dispatched more coal power plants and fewer natural gas plants, which led to the increase in emissions for this case. For the 2030 system, once again, the 40% non-spinning reserve cap recorded the highest increase in emissions relative to the baseline of 27%, while in contrast to the 2019 analysis, the 60% non-spinning reserve cap recorded the greatest decrease in emissions, as opposed to the 20% non-spinning reserve case. Once again, there was no clear pattern that emerged in regards to the non-spinning reserve cap that was set and the level of emissions that were observed. The key takeaway with regards to emissions from this analysis was that emissions would not be significantly impacted regardless of how it was determined to partition reserves between spinning and non-spinning.

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Appendix

Detailed Reserve Definitions from various Resources:

NERC:

"Operating Reserves - Spinning is generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or load fully removable from the system within the Disturbance Recovery Period following the contingency event" (NERC 2021).

PJM:

"Contingency reserves shall not be less than the largest contingency and they must be made up of at least 50% spinning reserves. Synchronized reserve is the amount of power (connected to the grid) that can be received within 10 minutes. Primary reserve is the amount of power that can be received within 10 minutes. Quick start reserve is the amount of power that can be received within 10 minutes from generators that are offline. Supplemental reserve is the amount of power that can be received within 10 to 30 minutes" (PJM 2019).

CAISO:

"Spinning reserves are reserved capacity provided by generating resources that are running with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least 2 hours. Non-spinning reserves are generally reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least 2 hours" (California ISO 2008).

Brattle Report:

"Spinning reserves are power sources that are online and synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output usually within 10 minutes. Non-spinning reserves are the same as spinning reserves, but do not need to respond immediately; units can be offline but still must be capable of reaching the committed output level within the required time" (Shavel et al 2015).

FERC:

"Spinning reserves are provided by generators that are on-line (synchronized to the system frequency) with some unloaded (spare) capacity and capable of increasing its electricity output within a specified period of time, such as 10 minutes. Synchronized reserve can also be provided by demand-side resources. Non-spinning reserves are provided by generating units that are not necessarily synchronized to the power grid, but can be brought online within a specified amount of time, such as 10 minutes. Non-spinning reserves can also be provided by demand-side resources" (FERC 2020).

<u>2023 DEC & DEP Generation Portfolio</u>:

Nuclear: 11,113 MW

Coal: 9,320 MW

Hydroelectric/Pumped Hydro: 3,582 MW

Natural Gas: 11,975 MW

Solar: 333 MW

Energy Storage: 9 MW

Combined Heat and Power: 16 MW

(Carolinas Carbon Plan 2022)

<u>Schematic of GRACE's Current Practice Model</u>:

The schematic of the CPM model provided by the GRACE project (GRACE 2023) is given below. The description of the same is written in Section 2.5.

Figure 1: GRACE's CPM