

ACHIEVING CLEAN AIR ACT
SECTION 111(D) CARBON
REGULATION COMPLIANCE VIA
NUCLEAR LOAD-FOLLOWING IN
THE SOUTHEASTERN UNITED
STATES

Research in Partial Fulfillment of Requirements for the
Degree of Master of Science in Natural Resources at the



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Introduction, Motivations & Context:

As the effects of climate change loom nearer and threaten the global community at large, it is imperative that major emitters of greenhouse gasses (GHGs) begin to curb their rates of emission to limit and mitigate those impacts. Carbon dioxide (CO₂) is the largest single component of GHGs in the atmosphere comprising roughly 400 ppm, according to the National Oceanic and Atmospheric Administration (NOAA)¹. In 2012, just over 82% of GHG emissions in the United States were embodied as CO₂ with methane (CH₄) as the second highest form of GHG emissions at just under 9%. According to the United States Environment Protection Agency's (EPA) GHG Inventory, the power sector comprised just over 31.6% of all GHG emissions across the nation².

Power systems are operated such that the lowest cost non-variable resources are generally brought online to meet demand and more expensive, non-variable sources of generation are brought online subsequently as demand increases in real time and more online generation capacity is necessitated. Most often, this lowest cost resource comes in the form of nuclear and coal-fired power. Compared to other non-variable, non-renewable fuel sources (i.e. natural gas & nuclear fuel rods), coal is particularly carbon-intensive and poses a number of other associated health and atmospheric risks³.

In response to the growing threats of climate change and in an attempt to de-carbonize the power sector the EPA began to field comments on CO₂ regulation in 2013, and moved forward with publication of its proposed 'Clean Power Plan' (CPP) in 2014⁴. The EPA derived its rulemaking authority from section 111(d) of the federal Clean Air Act. A year-long comment period followed, and, on 3 August 2015, the EPA released its final rule, which was subsequently published in the Federal Register on 23 October of the same year⁵. While many states have internal goals for the power sector via Renewable Portfolio Standards (RPS) and other state-level tax incentives for renewable generation to complement the existing federal Investment Tax Credit (ITC) and Production Tax Credit (PTC), the CPP represents the first federal regulation on CO₂ as an air pollutant.

Section 111(d) of the Clean Air Act pertains to the regulation of harmful pollutants resulting from existing stationary sources of pollution and excludes those 187 hazardous air pollutants (HAPS) specifically mentioned and regulated under section 112 of the same statute⁶.

The proposed and final rule both require a reduction in CO₂ emissions from all existing electrical generating units (EGUs) greater than 25 MW in generating capacity by 2030 on a state-by-state or region-by-region basis⁷. This allows for states to comply by achieving CO₂ emission reductions alone or in conjunction with partner states, requiring associated states to coordinate amongst themselves.

Emission reduction compliance can either be achieved through a mass-based system, meaning that annual emissions (in tons CO₂/year) from EGUs in a state or collection of states will be the benchmark of compliance, or a rate-based scale which looks at average emissions across the entire fleet of regulated EGUs within a state or partnered group of states as measured in lbs CO₂/MWh⁷.

Existing generation sources under the EPA's final rule pertain to all units that are online prior to 2020. States attempting compliance must submit a compliance plan, often called a 'state implementation plan' (SIP) by 2016, while those states working in tandem must submit their SIPs to the EPA for approval by 2018. In general, the EPA requires a 30% mass reduction in annual emissions or a 30% reduction in rate of CO₂ emissions by 2030 based on 2005 emissions levels⁶.

The EPA recommends three building blocks for compliance: 1) improving heat rates at existing facilities, 2) switching coal units to natural gas units, and 3) developing emission-free resources⁶. In addition, it should be noted that energy efficiency will also likely play a critical role in achieving targets at the state level. A fourth block for demand-side management and end-user energy efficiency was initially included in draft released for public comments in 2014. It has since been removed, but remains a viable compliance strategy that states are likely to include as part of their emissions compliance strategies⁸.

While renewable energy in the form of wind and solar technology, is often touted as a means of achieving the needed reductions in power sector GHG emissions, it should be noted that such power is variable and cannot reliably serve as baseload capacity to meet energy demand. Such power sources often prove effective for shaving a system’s demand profile and curbing the probability that smaller, generally more carbon intensive ‘peaking’ plants need to come online. This is not to say that there is no value derived from the generation that occurs during off-peak hours and mitigates emissions by allowing for baseload capacity to ramp down. These sources are particularly dependent on tax credit subsidies which expire and require relatively frequent renewal^{9,10}. These resources are also highly geographically dependent. Siting the same 100 MW of solar PV generation capacity in two different geographic locations can have wildly different implications for the greater grid to which this generation is interconnected¹¹. In addition, hour-to-hour generation can vary differently as well at a given site¹².

Non-variable renewable energy (i.e. biomass generation) often requires feedstock with competing value chains, and the means by which feedstock is processed and delivered is not as streamlined or viable at the same scale as natural gas and coal.

As energy companies in the United States begin to extract natural gas resources that were previously untapped via hydraulic fracturing (‘fracking’), pipeline natural gas, which is less carbon intensive than coal and results in fewer particulate matter-related health issues, has become cheaper and is becoming more cost-effective at larger scales than has previously been the case (see *Figure 1*)¹³. In addition, compared to bituminous coal, combustion of natural gas results in a 43% reduction of CO₂ emissions when compared with bituminous coal per MMBtu of fuel combusted¹⁴.

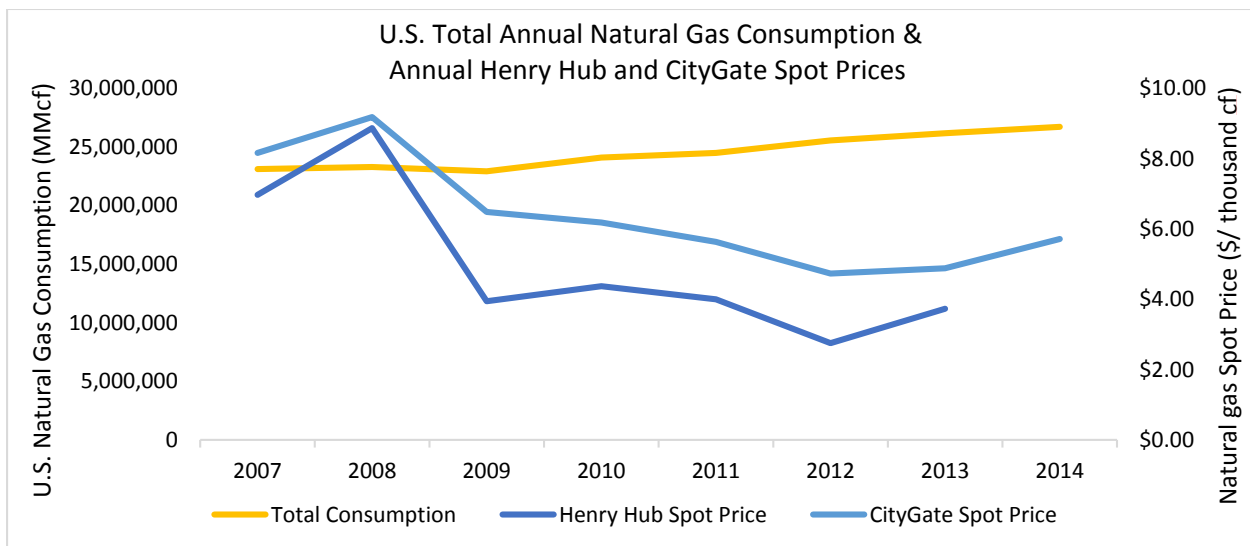


Figure 1. Falling natural gas spot prices and rising consumption nationally¹⁵

Still, natural gas-fired generation remains relatively more expensive on the basis of fuel costs, and typically natural gas combined cycle (NGCC) generation units are dispatched after coal units and followed by the less efficient natural gas combustion turbine (NGCT) units. By contrast, nuclear generating units (NGUs) are often dispatched before coal units for baseload power and result in no carbon emissions ¹⁶.

The major drawbacks for NGUs lie in their high capital cost and likelihood of cost overruns during construction, issues over siting concerns related to environmental health and safety (EHS), lack of long term disposal solutions for radioactive waste, and the proliferation of nuclear materials as an international safety threat ^{17, 18}. As mentioned previously, a major reason that utilities, particularly those participating in ‘day-ahead’ and ‘hour-ahead’ competitive capacity market auctions managed by Independent System Operators (ISO) and Regional Transmissions Organizations (RTO), lack the incentive to invest in new NGUs, and, in some cases, have started to consider retiring some NGUs, lies in the recent fall in price and lack of relative historic volatility in natural gas prices ¹⁹. Despite these challenges, five nuclear units are currently under construction in the United States- all within Region II of the Nuclear Regulatory Commission’s (NRC) jurisdiction ²⁰. This region covers all of the states of Alabama, Florida, Georgia, Kentucky, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

Of the 104 NGUs in operation in the US, 37 fall within this region, comprising just under 36% of all national nuclear capacity. While Kentucky and West Virginia, whose economies depend heavily on coal extraction, do not contain any NGUs, the remaining seven states have at least one NGU. Of those remaining seven states, all but Florida receive more than a quarter of their electricity generation from nuclear power, with South Carolina receiving more than 58% of its electric power from NGUs and North Carolina coming in second within NRC Region II receiving roughly just over 39% of its power from NGUs (see *Figure 2*)^{20, 21}. All units being built in this region are being built by utilities that do not bid into competitive markets, and due to the high level of vertical integration engage regularly with state Public Services Commissions (PSC) to ensure the enforcement of anti-trust legislation and protect consumers from electricity rate-gouging ²². Investment in new assets ensures that the utility can justify higher rates over the time taken to recover the costs of acquiring new assets ²².

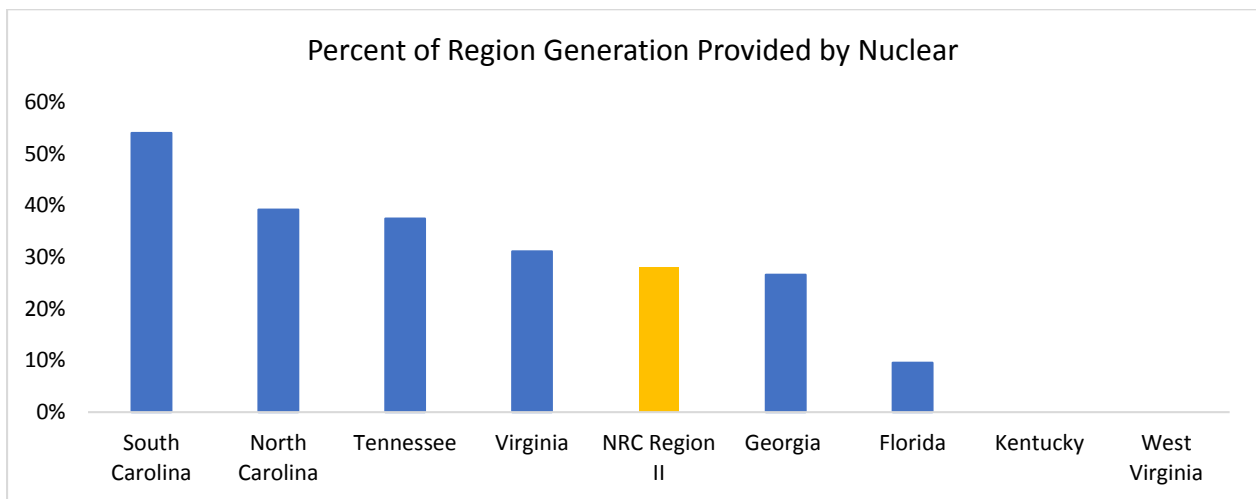


Figure 2. Percentage of state generation provided by nuclear generation across NRC Region II States ranked from lowest to highest.

These investor owned utilities include SCANA subsidiary South Carolina Electric & Gas (SCE&G) and Georgia Power (in conjunction with fellow Southern Company subsidiary Southern Nuclear), alongside the federally-owned the Tennessee Valley Authority. In South Carolina alone, each of the two new NGUs under construction represents 1,117 MW of future system capacity ²³.

In the U.S., NGUs are most often dispatched as low-cost baseload power and operated almost continuously at nearly full capacity. This requires little change in the operational capacity of NGUs. Typically NGUs in the US have high capacity factors (CF), meaning that they run at nearly full generation capacity over the course of a given year, save for maintenance, which is largely due to refueling. Across North Carolina’s portfolio of five NGUs the capacity-weighted CF exceeded 92 ²⁴. That number was only slightly lower across South Carolina’s portfolio of seven existing NGUs at 91% ²⁴. Generally these facilities are run at 100% of rated power when operational. Shutdowns are typically due to regular scheduled maintenance, including refueling periods which happen roughly every 18 to 24 months ²⁵. Overall, national electricity supply is only roughly 20% dependent on nuclear generation ²⁴. By contrast, annual electrical generation in France exceeds three-quarters of all electricity generation ²⁵. This is possible not only because of the relatively high collective capacity of France’s NGUs, but also as a result of the ability to use such units to balance load and real-time demand ²⁵.

Load-following is defined as the ability of any generation to respond to demand in near real-time by ramping up load as needed ²⁴. This means that there is available capacity for units that allows units to adjust generation. This is typically done to minimize system costs for generation ²⁶. This also becomes potentially useful for CO₂ mitigation when generation from a relatively more emissions-intensive source can be displaced by extra capacity from a new less emissions-intensive source. Typically generation that only comes online during peak hours (which tend to be low CF units) are targeted as possible sources to retire via load-following with a cheaper (or less emissions intensive) source. Nuclear energy stands to meet both these cost and emissions intensity requirements. A sample load curve with and without load-following can be found below:

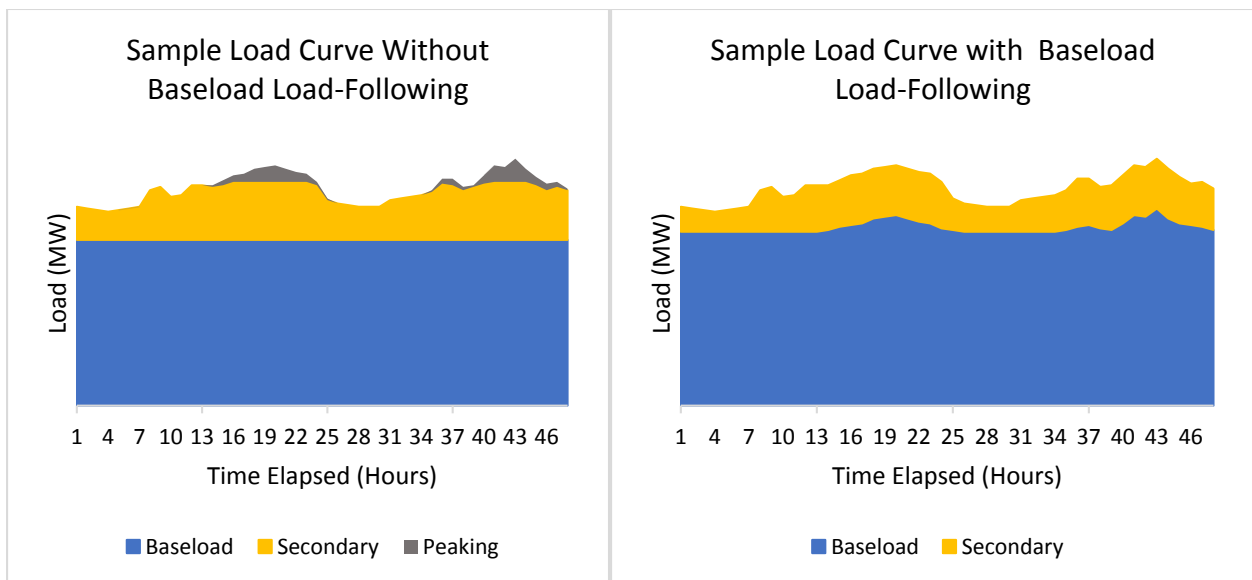


Figure 3. Sample load curves following a 48 hour generation period to exemplify the benefits of load-following to shave peaking generation.

The addition of baseload capacity with load-following capability keeps total generation the same, but displaces all ‘peaking’ generation. The 2014 generation mix in North and South Carolina totals 112 and 92 TWh, respectively (see *Figures 4 & 5*).

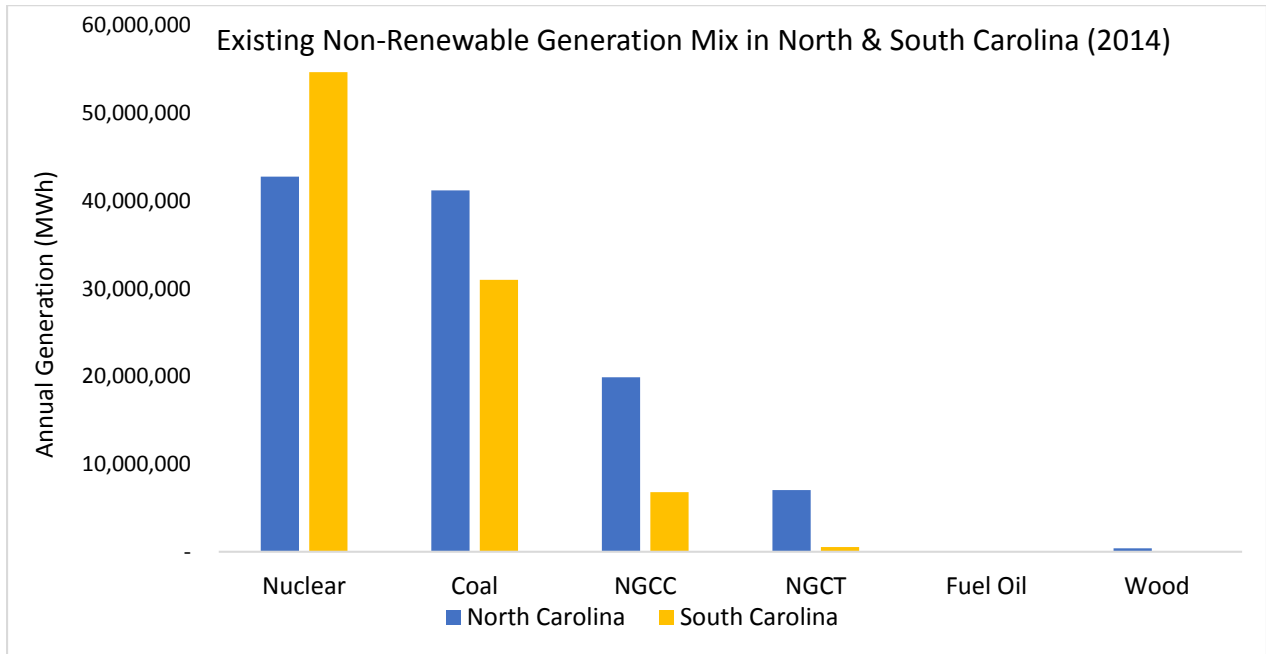


Figure 4. 2014 Annual Generation by Fuel Source for North & South Carolina

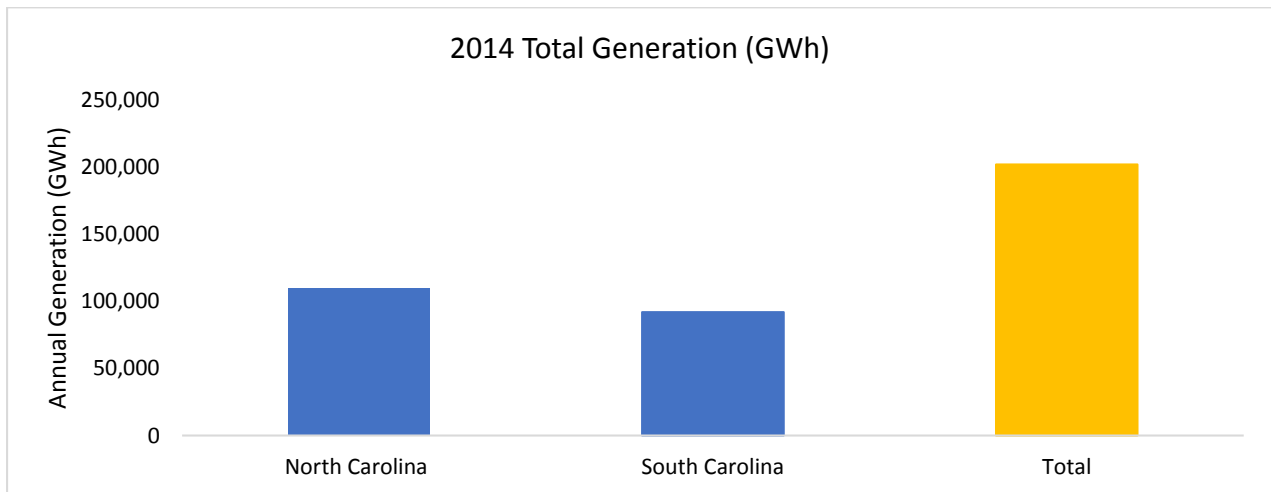


Figure 5. 2014 Annual Generation by State

In 1991, the European Utilities Requirements (EUR) required that NGUs be able to operate continuously between 50% and 100% of the unit’s capacity²⁷. Similar standards were actually first put forth by the US-based Electric Power Research Institute (EPRI) as a means of standardizing nuclear reactor designs for approval internationally earlier that same year. This means that while some nuclear power might be devoted to baseload power, as is the case with all NGUs in North Carolina and South Carolina, other units may operate with CFs well below 90% so that demand can be met in real-time via ‘load-following’, and it is likely that those secondary units operating at higher CFs are smaller in scale than those NGUs

being used as baseload power. Thus, the need for older, smaller, and more carbon intensive peaking plants is mitigated and so too are the CO₂ emissions associated with this relatively carbon intensive electric generation.

For the duration of this study, nuclear load following will be examined as a means of achieving CPP compliance within the states of North and South Carolina whose state boundaries fall entirely within the bounds of Southeastern Reliability Corporation (SERC) balancing authority sub-region VA-CAR (indicating that it is responsible for balancing load within parts of Virginia, and almost all of North and South Carolina. Compliance via nuclear load-following will solely be examined from the perspective of single-state, mass-based emission reduction compliance.

Thus far, relatively little has been done to analyze the role of nuclear load-following in carbon mitigation, though the subject of using nuclear generation to bridge the gap to a clean energy transition, is one that is particularly divisive with regard to curbing the effects of climate change. Much of the available data and what is known about economic nuclear load-following is the result of proprietary information and company-specific trade practices that provide large French electric utilities and associated contractors and operators (e.g. Électricité de France S.A. & Areva GMBH) the ability to expand their lines of business internationally ²⁵.

In addition to this, the designs of nuclear reactors intended to meet EUR capabilities must be proposed and approved for construction by the NRC ²⁵. However, since until recently, the development of new NGUs has been sluggish at best, those entities currently looking to install new builds are primarily looking to replace baseload coal. After a certain point, load following capabilities will be a necessity for new builds ²⁵.

While load-following is permissible in the U.S., its automation is not permitted in the same manner that automation of generation is permitted for non-nuclear sources ²⁷. Load-following is required to be done manually only by those operators legally permitted to. This is a result of security concerns surrounding the manipulation of software used for such operation and the potential disastrous consequences that are associated ²⁷.

Research Questions:

- 1) How many new NGUs are required to achieve CPP regulatory emissions compliance using economic dispatch of generation?**
- 2) What are the annual costs associated with incremental NGU builds needed for compliance using economic dispatch?**
- 3) How much CO₂ mitigation is achieved with each incremental economically dispatched NGU addition?**
- 4) At what point does load-following become necessary for additional NGUs, and does this occur before or after the number of new NGUs needed for CPP compliance?**

Methods:

Hourly System Emissions:

The EPA's Acid Rain Program (ARP) data for the year 2014 was used to derive hourly fossil CO₂ emissions in North and South Carolina separately ²⁸. The hour-by-hour non-nuclear generation was sorted by

generation type as either ‘Coal’, ‘Natural Gas Combined Cycle’ (NGCC), ‘Natural Gas Combustion Turbine’ (NGCT), or ‘Fuel Oil’ generation (primarily comprised of diesel oil, and otherwise assumed to be). In the case of North Carolina, wood-fired generation was considered a ‘must-take’ resource and was not displaced by new generation. These generation type distinctions were confirmed by crosschecking ARP data with the EPA’s National Electrical Energy Data Systems (NEEDS v.5.15), which serves as the modeling basis for the CPP with regard to existing generation²⁹. This information was used to assess baseline emissions for existing generation, as outlined in *Equation 1*, and cost inputs were subsequently used for further analysis³⁰.

Hourly System Emissions=

$$(X_{i-Coal})(Q_{i-Coal})(C_{i-Coal})+(X_{i-NGCC})(Q_{i-Natural Gas})(C_{i-Natural Gas})+ \\ (X_{i-NGCT})(Q_{i-Natural Gas})(C_{i-Natural Gas})+ \\ (X_{i-Diesel})(Q_{i-Diesel})(C_{i-Diesel})$$

Equation 1. Calculating Hourly System Emissions

Here **X** indicates generation for a given hour of year, **i**, **Q** indicates generation-weighted, average heat rate for same given hour (in MMBtu/MWh), and **C** indicates the CO₂ emissions rate specific to the fuels outlined in the table below:

Bituminous Coal	Natural Gas	Fuel Oil
0.10285 tons CO ₂ /MMBtu	0.0585 tons CO ₂ /MMBtu	0.08065 tons CO ₂ /MMBtu

Table 1. Carbon Intensity of Fuel Combustion³¹

All coal was assumed to be bituminous given the close geographic proximity to Appalachian coal supplies. Similarly all fuel oil was assumed to be diesel in the absence of more specific data on generation.

When summed across each generation type, as shown in *Equation 1*, this provides total emissions for each scenario in which another NGU is added. The difference in scenario summations was used for comparison of annual avoided emissions. *Figure 6* displays the hourly emissions for existing generation.

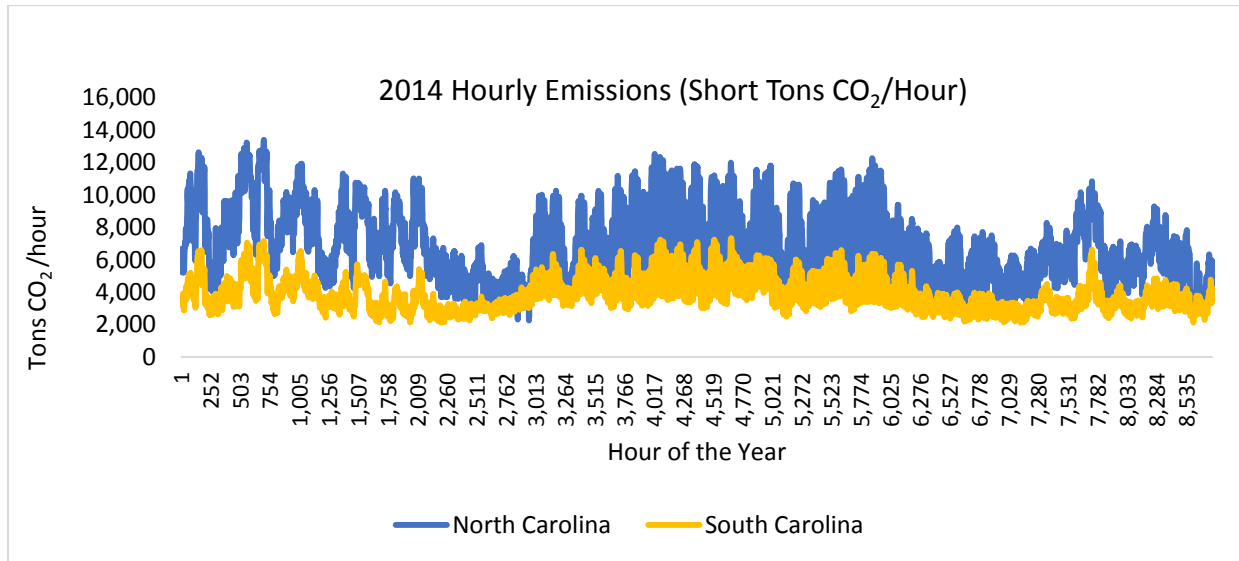


Figure 6. 2014 Annual Hourly Emissions in North & South Carolina

This was used to determine the emissions resulting from each scenario in which a 1,000 MW NGU was added to displace existing fossil generation in a manner compliant with *economic dispatch*. This means that nuclear power was first used to displace Fuel Oil generation, followed by NGCT, NGCC, and Coal generation, respectively as can be seen in Equation 2.

Hourly NGU Generation Displacement=

$$(G_{i-Fuel\ Oil})_i - 1,000\ MW_{Nuclear} = \Delta G_{i-Fuel\ Oil};$$

If $\Delta G_{i-Fuel\ Oil} < 0$, then $\Delta G_{i-Fuel\ Oil} + (G_{i-NGCT}) = \Delta G_{i-NGCT}$;

If $\Delta G_{i-NGCT} < 0$, then $\Delta G_{i-NGCT} + G_{i-NGCC} = \Delta G_{i-NGCC}$;

If $\Delta G_{i-NGCC} < 0$, then $\Delta G_{i-NGCC} + G_{i-Coal} = \Delta G_{i-NGCT}$;

If $\Delta G_{i-NGCC} < 0$, then $\Delta G_{i-Coal} + G_{i-Nuclear} = \Delta G_{i-Nuclear}$;

Where G represents system generation for a given hour i , and

If a given $\Delta G_i > 0$, then all remaining existing generation in the economic dispatch sequence remains the same as in the previous scenario. In addition, if $\Delta G_i < 0$ for a given fuel type, then reported hourly load for that type of generation is reported as 0 MW.

Equation 2. Hourly Generation Assessment

This order was chosen on the basis of historical fuel prices. These addition scenarios built upon one another until further builds reached a CF of zero. Calculation of avoided emissions was used to determine the point at which an addition allowed for emissions compliance as outlined by the 2030 CO₂ emissions goals states in the EPA's State Factsheets³². Figure 7 shows a needed 15.8% and 24.9% reduction in emissions in North and South Carolina, respectively.

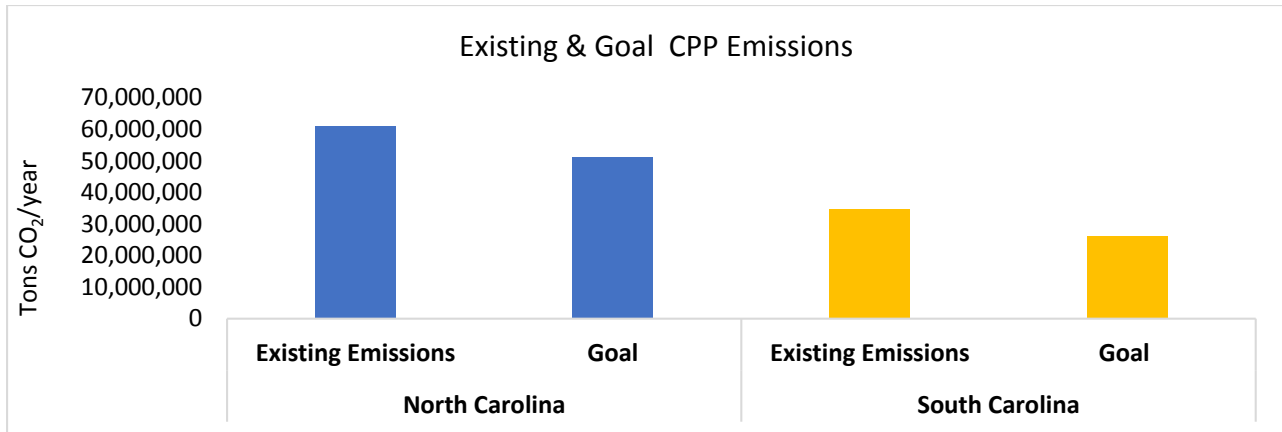


Figure 7. Existing Emissions & Target Emissions in North and South Carolina

In addition to this, NRC annual data on nuclear capacity shutdowns, which was generally the result of scheduled maintenance, and used to more accurately model nuclear load changes across the year²⁰. This helped to provide a more accurate picture of how such maintenance would affect the overall system, rather than assuming that all plants ran at a capacity-weighted, average CF across all hours.

Levelized Cost of Energy & Net Annual Cost of Generation:

The total existing nuclear and fossil loads along with hourly emissions and generation data were then used to derive the CF, cost, and frequency of load-following that would subsequently be performed by additional nuclear capacity additions used to replace fossil generation. The additions were simulated to reflect system replacements of fossil generation with nuclear generation³⁰. The resulting CFs and assumptions from the EIA’s ‘Updated Capital Costs for Utility Scale Electricity Generating Plants’ were used to derive a levelized cost of energy (LCOE) based on an assumed 25% increase in fuel costs due to nuclear load following practices^{26,30}. LCOE calculation can be found in *Equation 3*.

LCOE =

$$\{[(\text{Overnight Capital} * \text{CRF} + \text{Fixed O\&M}) / ((8766 \text{ hours}) * \text{CF})] + [(\text{Fuel cost}) + \text{Variable O\&M}]\}$$

Equation 3. Levelized Cost of Energy

The above inputs were derived from the most recent EIA reporting on capital costs of new advanced nuclear with a CRF calculated based on a 50 year capital recovery period, *n*, at a 10% discount rate, *i*³⁰. This CRF, which was subsequently used in the above LCOE formula, was calculated using *Equation 4*.

$$\text{CRF} = (i(1+i)^n) / \{[(1+i)^n] - 1\}$$

Equation 4. Capital Recovery Factor

Based on LCOE and CF values associated with additional builds, annual costs of generation were derived and subsequently used to determine CO₂ mitigation on the basis of \$/short ton of CO₂ mitigation. However, to reflect avoided fuel costs resulting from displaced fossil generation, the net annual cost of generation was derived using *Equation 5*.

$$\begin{aligned}
 & \textbf{Net Annual Cost of Generation} \\
 & = \{\text{Annual Cost of Generation}\} - \{\text{Annual Avoided Fuel Costs}\} \\
 & = \{(LCOE * CF * \text{Rated Capacity})\} -
 \end{aligned}$$

$$\left\{ \sum \left[(G_{Diesel} * HR_{Diesel} * K_{Diesel}) + (G_{NGCT} * HR_{NGCT} * K_{Natural\ Gas}) + (G_{NGCC} * HR_{NGCC} * K_{Natural\ Gas}) + (G_{Coal} * HR_{Coal} * K_{Coal}) \right] \right\}$$

Where:

LCOE is the levelized cost of energy for the unit addition in **\$/MWh**

CF is the capacity factor of the unit addition in %

G is the hourly generation by generation type in **MWh**

HR is the hourly heat rate by the generation type

K is the cost of fuel by type in **\$/MMBtu**

Equation 5. Net Annual Cost of Generation

Cost of mitigation for each incremental build was calculated by merely dividing annual mitigated emission by the net annual cost of generation for each unit to arrive at a figure in terms of \$/ton mitigated. Modeled cost of fuels as derived from the EIA can be found below:

Bituminous Coal	Natural Gas	Diesel Oil
\$2.41/MMBtu	\$5.89/MMBtu	\$27.88/MMBtu

Table 2. 2014 Average Annual Fuel Prices for modeled fuels (\$/MMBtu) ^{33,34,35,36}

Public data for natural gas prices in the electric power sector was drawn from the EIA, however, 2014 data was withheld for the South Carolina, as doing so would inherently divulge information about a single company ³⁵. In lieu of actual data, electric power sector natural gas prices in South Carolina were assumed to be the same as for North Carolina.

Because substitution of existing peaking generation for more efficient NGCC generation is often thought to be a major alternate strategy for CPP compliance, a comparison of how the construction and resulting projected cost of new Advanced NGCC (A-NGCC) units might affect the state-level system emissions was deemed necessary. A-NGCC replacements were applied for CO₂ mitigation in 400 MW intervals such that economic dispatch was only applied to displace existing Fuel Oil, NGCT, and existing NGCC generation. Due to the historically lower dispatch costs of coal and nuclear generation, none of this generation was displaced by A-NGCC additions. This comparison was made taking into account a capital recovery period of 20 year at a discount rate of 5.5% ³⁰. The heat rate of 6.43 MMBtu/MWh for such generation was also derived from the EIA's 'Updated Capital Costs for Utility Scale Electricity Generating Plants' and assumed to be a static input across all hours ³⁰.

Capital Cost Sensitivity:

In addition, a sensitivity analysis was conducted by adjusting the per MW capital cost assumptions to model the impacts of cost overruns at 10%, 20%, 30%, 40%, and 50% on net annual generation costs. All

analysis was conducted in Microsoft Excel 2013, and supporting data can be accessed in '.xlsx' format by contacting the author via e-mail.

Results:

NGU Additions

For CPP compliance it was found that two NGUs, which displaced all existing fuel oil, NGCT, and NGCC generation, and some coal generation, were needed to meet CPP compliance in South Carolina. Three NGUs were needed to meet CPP compliance in North Carolina. However, peak avoided emissions occurred with the addition of more NGUs as seen in *Figure 8*.

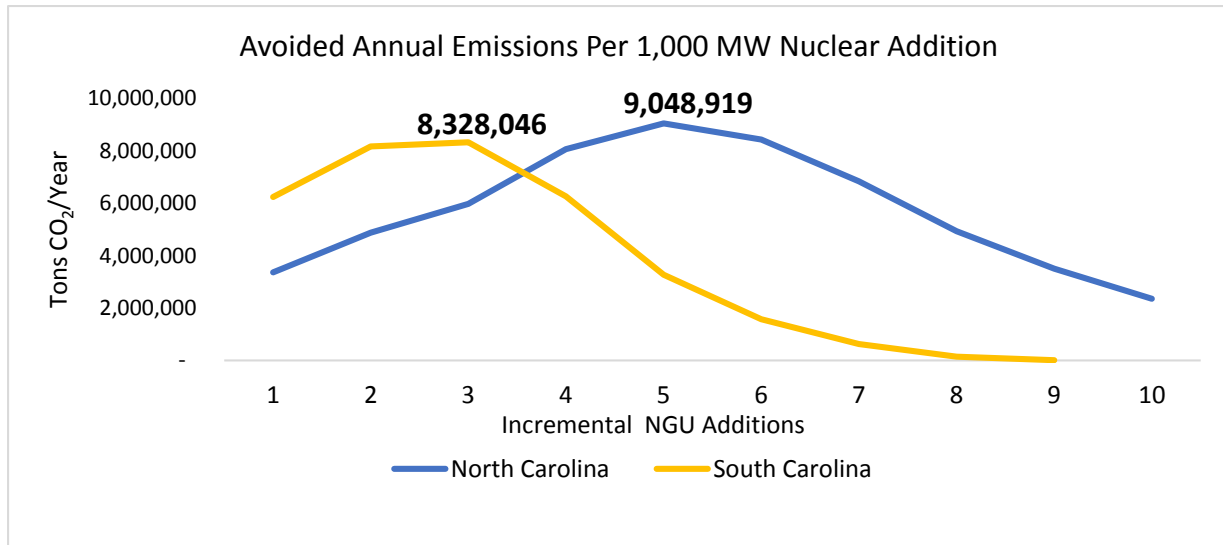


Figure 8. Annual avoided emissions per 1,000 MW nuclear generating unit (NGU) addition with peak avoided annual emissions displayed for North and South Carolina systems

Peak avoided emissions for a given unit happened in South Carolina occurred with fewer additions not only because of the difference in annual demand, but also as a result of the generation mix. The relative greater presence of nuclear generation in South Carolina and the relatively lower amount of fuel oil, NGCT, and NGCC generation as compared to North Carolina means that a single NGU addition immediately begins to displace baseload coal generation, which is very CO₂ intensive. This peaks as the NGU additions start to displace mostly baseload coal while maintaining a high capacity factor. By contrast, much of the generation displaced by initial nuclear additions in North Carolina is spent displacing the relatively less CO₂-intensive generation provided by NGCT and NGCC generation. The cumulative mitigated emissions as function of number of NGUs added to each state system

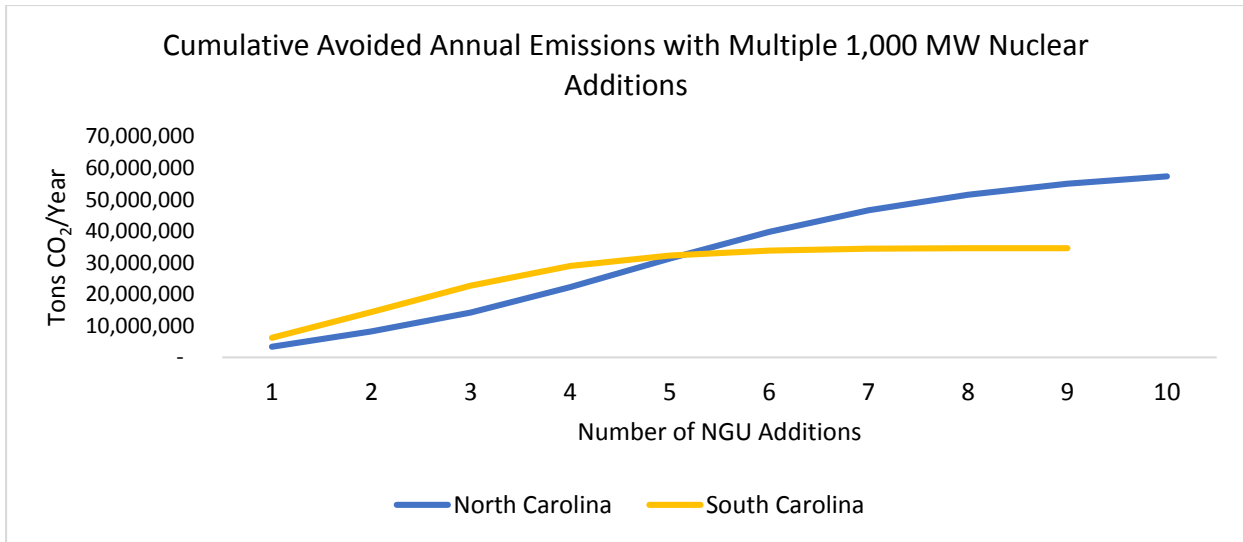


Figure 9. Annual avoided emissions give the number of 1,000 MW nuclear generating unit (NGU) additions for North and South Carolina

Figures 8 and 9 indicate that all emissions are theoretically mitigated at ten NGU additions in North Carolina and nine NGU additions in South Carolina. However, there are likely physical constraints surrounding this.

The third NGU addition in South Carolina had a CF just above 98%, while a fifth NGU addition in North Carolina would have a CF just under 95%. CFs for each addition by state can be found below.

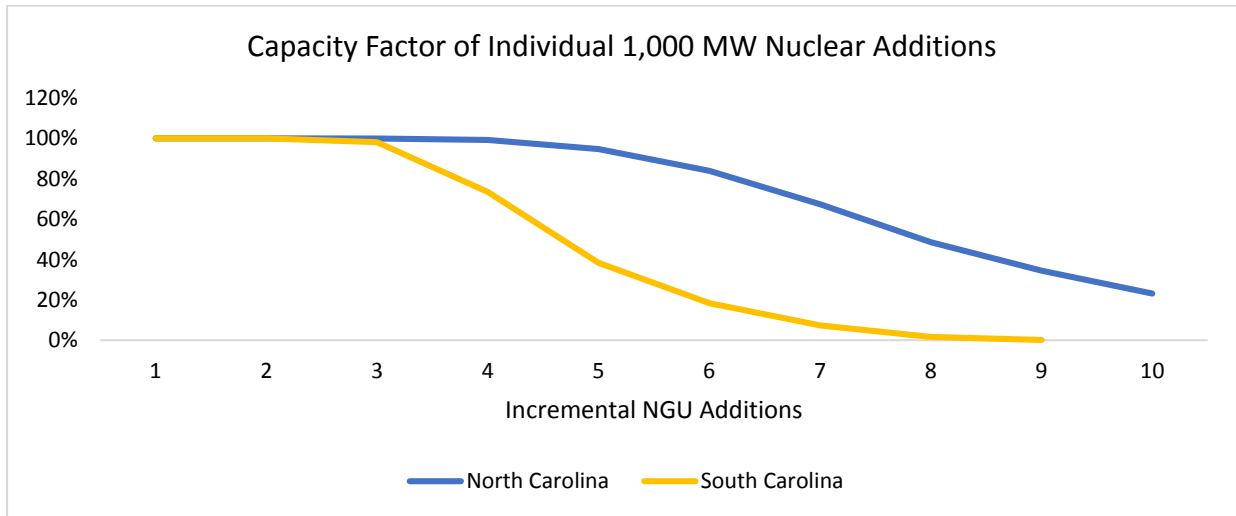


Figure 10. Capacity factor for each incremental nuclear generating unit (NGU) addition

As can be seen above, the CF for South Carolina’s NGU additions drop sharply after the third NGU addition. The fourth addition has a CF around 73%, and the next addition has a CF just above 38%. The cost of mitigation is correlated negatively with low CFs as demonstrated by comparison of Figures 10 and 11. R²-values of 0.8034 and 0.8261 were reported for North and South Carolina, respectively, for the observed negative correlation between CFs and cost of mitigation.

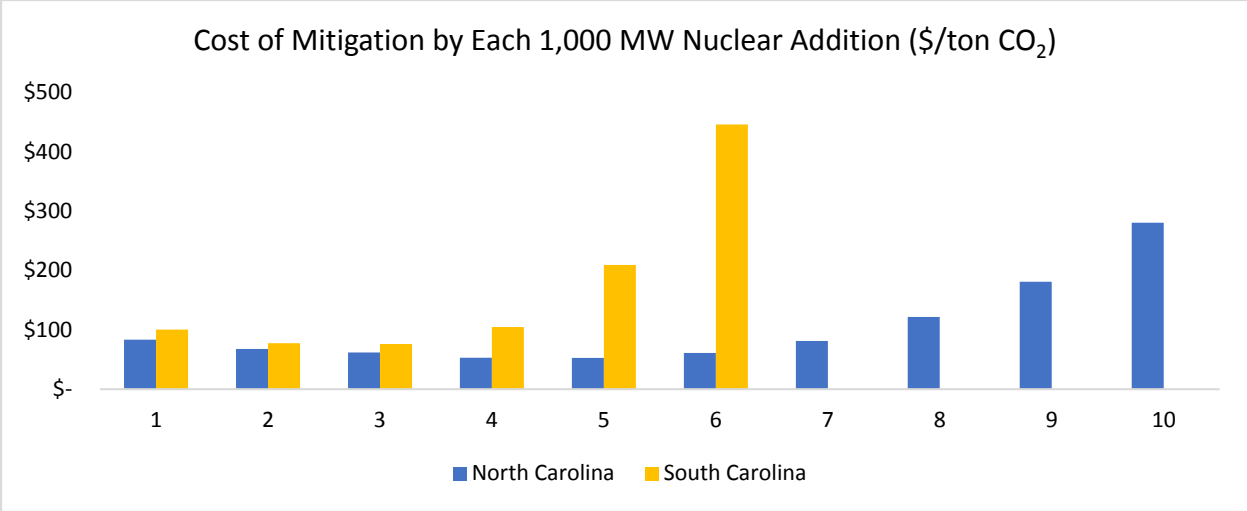


Figure 11. Per ton annual cost of CO₂ mitigation per 1,000 MW nuclear generating unit (NGU) addition

The price of mitigation calculated in \$/ton CO₂ mitigated, on the basis of net annual cost of generation, resulted in the lowest cost of carbon for the third and fifth NGU additions in North and South Carolina, respectively. In the graph above, cost of generation for seventh, eighth, and ninth South Carolina NGU additions were not displayed as costs reached prices that did not allow for comparative scale due to their relative magnitude. The net annual costs of generation per additional NGU can be found in Figure 12.

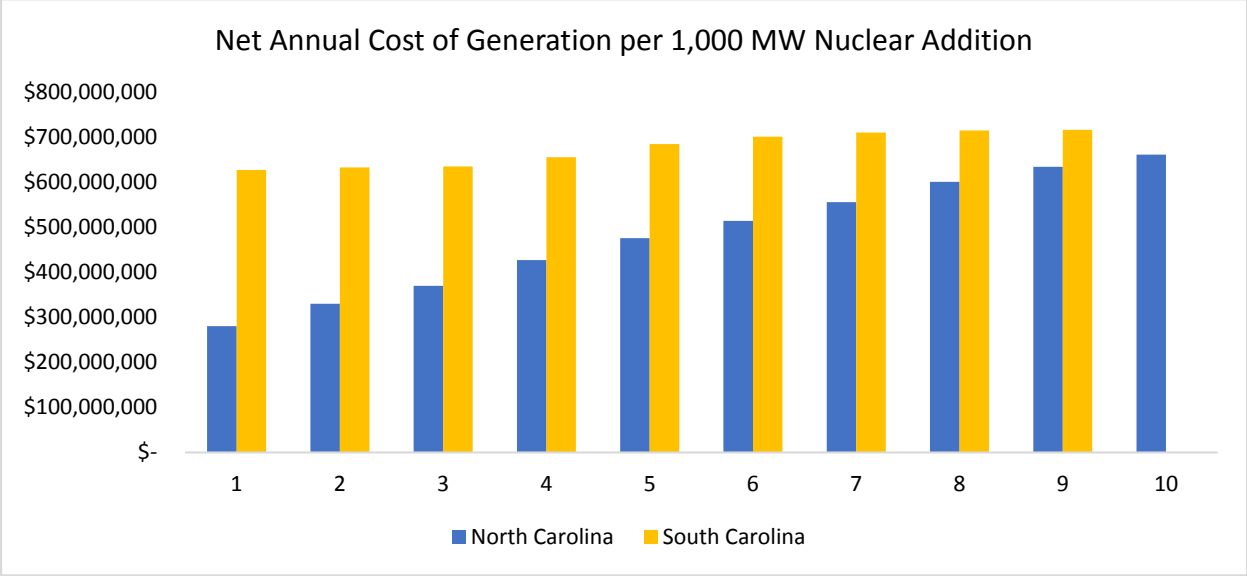


Figure 12. Net Annual Cost of Generation per 1,000 nuclear generating unit (NGU) addition as derived using Equation 3

A key feature of this finding is that the net annual costs of earlier nuclear additions in North Carolina are cheaper at every increment. This is in large part due to the fuel costs avoided, specifically with regard to natural gas prices. While coal makes up the next largest source of generation after nuclear in South Carolina, North Carolina is almost equally powered by coal and nuclear with large contributions from

NGCT and NGCC generation, both of which take priority for replacement over coal for economic dispatch of load-following nuclear units. As more NGUs are added to the system, the incremental unit net annual generation cost for the next NGU addition increases due to decreased CF and subsequent falling avoided fuel costs. The avoided fuel costs that result from NGU additions are as follows:

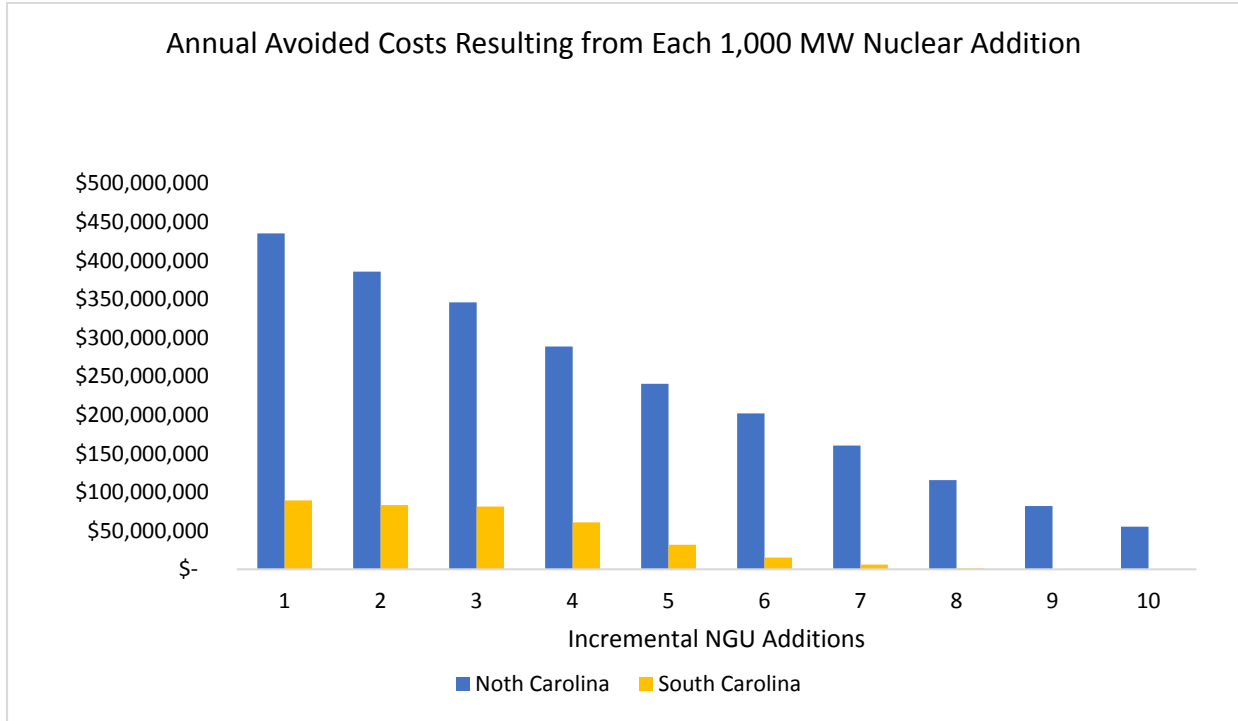


Figure 13. Annual fuel savings resulting from avoided generation with each incremental nuclear generating unit (NGU) addition

These avoided fuel costs, which are largely the reason for differences in cost of building new NGUs, results in the following cumulative net annual generation costs for these addition scenarios:

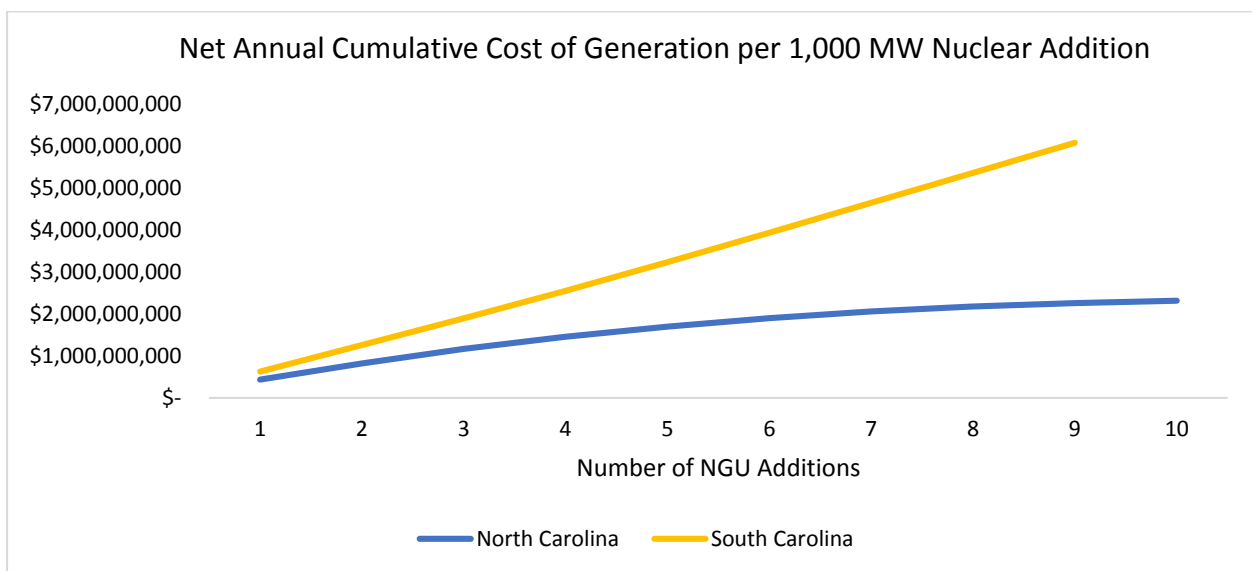


Figure 14. Net annual cost of generation given the number of 1,000 MW nuclear generating unit (NGU) additions added in North and South Carolina

The combination of relatively higher NGCC and NGCT penetration in North Carolina, proportionally higher penetration of coal in South Carolina, and overall higher baseload nuclear generation in South Carolina leave fewer potential avoided cost benefits to be from NGU additions in South Carolina. While the addition of nine NGUs in South Carolina totals upwards of \$6 billion, the addition of ten NGUs in North Carolina does not exceed \$2.5 billion.

In addition, by returning to the initial question of load-following and examining what proportion of the year was spent adjusting rated capacity by more than 1% of rated power/hour as compared the previous hour of generation, the following curves were derived:

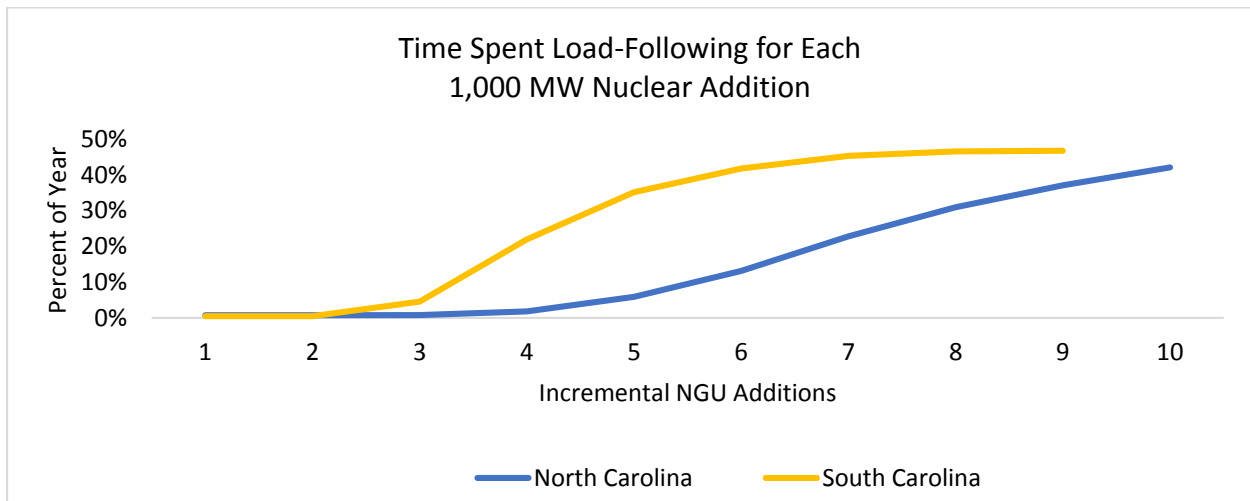


Figure 15. Time spent adjusting hourly load by more than 1% of rated power as compared to the prior hour for each nuclear generating unit (NGU) addition in North and South Carolina.

A-NGCC Additions:

The addition of A-NGCC units purely using economic dispatch did not result in emissions compliance in either North or South Carolina. The higher contribution of NGCC and NGCT generation in North Carolina’s generation mix allowed for the addition of 17 A-NGCC units via economic dispatch resulting in just over 2.38 million tons of CO₂ emissions mitigation. In South Carolina, this is largely due to the relatively low penetration of non-coal and non-nuclear generation. Here, only seven A-NGCC units were added until economic dispatch of generation did not allow for further CO₂ mitigations resulted in just under 1.76 million tons of CO₂. In addition the relatively low penetration of natural gas- fired generation leaves relatively little to be gained in the way of fuel savings. Additional units in South Carolina also had CFs that dropped off fairly quickly in comparison to the added A-NGCC units in North Carolina. See Appendix C for accompanying graphs.

Cost Overruns-Capital Cost Sensitivity Analysis:

As was previously noted in the introduction, NGUs are extremely capital intensive and it was found that that adjusting the capital cost inputs drastically altered the annual cost of generation in both states. The results are as follow:

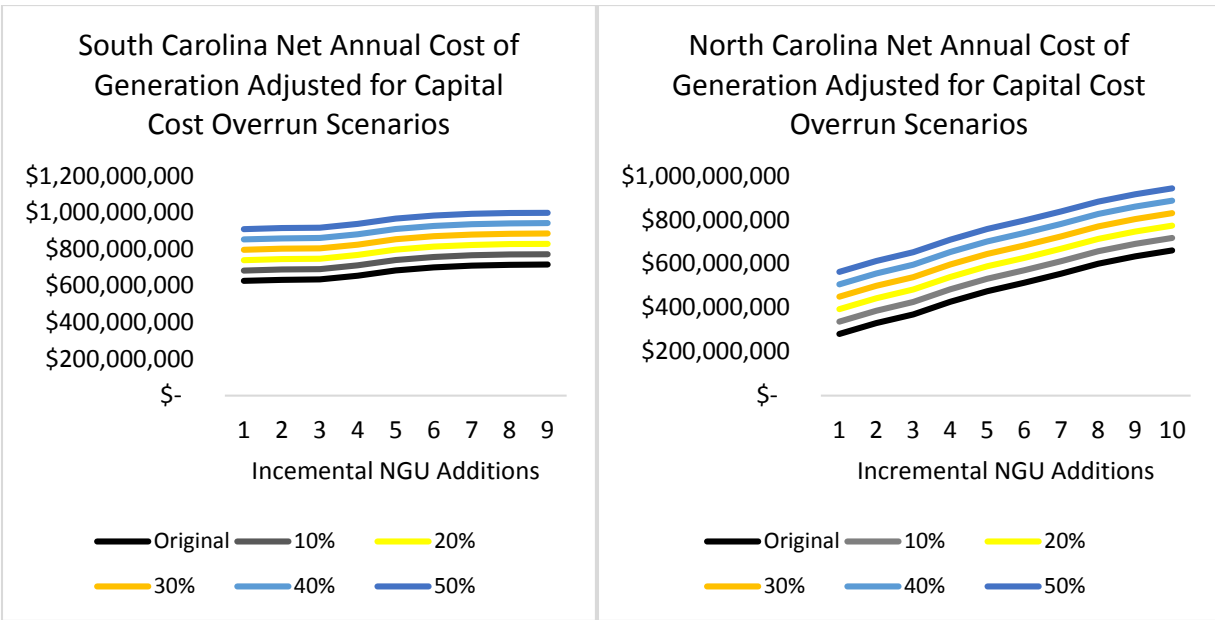


Figure 16. Sensitivity analysis of capital cost overrun adjustments on the net annual costs of generation for incremental nuclear generating unit (NGU) additions in North and South Carolina. Percentages in the key indicated the percentage by which capital costs have increased.

Discussion:

This study provided two major findings: 1) emissions compliance with NGUs in North and South Carolina is feasible regardless of whether or not those NGUs have load-following capabilities, and 2) avoided fuel costs play a major role in the cost-effectiveness of NGU additions.

Emissions compliance was theoretically achieved with two 1,000 MW NGU additions operating at a CF near 100% in South Carolina. As mentioned earlier, there are currently 2,234 MW of new nuclear capacity being built in South Carolina and set to come online after all SIPs are due for approval by the EPA^{13,15}. This represents more than enough CO₂-free generation to meet emissions compliance and leaves open the option of exporting zero-emissions generation which may potentially benefit surrounding states willing to pay a premium for the ability to comply and avert the usage of capacity that emits CO₂. Alternately, this also creates a situation in which South Carolina utilities may exceed mitigation goals and subsequently sell credits for a similar premium³⁷. From the perspective of surrounding states, this makes South Carolina as attractive state with which to partner from CPP compliance. In addition to potential revenue from tradable credits, the vertically integrated nature of utilities in both states, which results from natural monopolization, allows for future PSC hearings from which these utilities stand to justify higher rates in order to recover the cost of these NGU-associated assets. This means that utilities stand to realize larger annual revenues.

Despite the possibility of CPP compliance in South Carolina with NGU builds currently underway, both states filed suit against the EPA in October 2015 as a part of a larger group of 27 states challenging the court in the D.C. Circuit Court. In February 2016, the US Supreme Court put a freeze on the CPP with expected D.C. Circuit Court hearings to take place in June 2016³⁸. In South Carolina, this is a sign of a more ideologically driven conflict given that construction has already commenced and cost overruns

have already totaled \$698 million at a minimum, requiring the involved utilities- SCE&G and the state-owned Santee Cooper- to file for an adjusted schedule of capital recovery ³⁹.

In North Carolina, however, resistance to CPP compliance via NGU additions may simply be the result of an unwillingness of utilities to engage in the capital risks associated with construction of such a facility, though similar ideological aversion for regulation cannot be ruled out as one of many other forces at play. It should also be noted that, Duke Energy, the parent company of both major utilities in North Carolina also operate outside the state and has a number of assets that bid into the competitive PJM and Midcontinent Independent System Operator (MISO) markets ⁴⁰.

Amongst those other forces at play are the lack of positive public perception of nuclear power plants, lack of long-term waste disposal methods and plans, EHS concerns from the public, specifically related to reactor meltdowns (especially in light of events at the Fukushima Daiichi Plant in Japan), and opposition from ratepayer advocacy groups who see such investments as high risk for the interests of end users ^{41, 42, 43}. In total, only 51% percent of NGU licenses that have been filed for by utilities in front of the NRC have actually resulted in construction of NGUs ⁴². Of those projects brought online, the same percentage have fulfilled expected operation in line with the original granted license, and cost overruns still plague new NGU builds despite the expectation that standardization of reactor designs would mitigate this burden ⁴². Major banks have also previously declared that private finance without federal and state government fail-safe, loan guarantees is not feasible for NGU development and utilities have increasingly looked shift cost burdens to taxpayers and ratepayers, which has fostered much public opposition, and in turn has utility shareholders on the fence about pursuing such projects and incurring the costs of legal battles necessary to ^{41, 42}. In addition, 22 NGUs have had outages lasting more than five years ⁴². These already existing concerns for utilities and their shareholders are compounded by the need to increase safety measures in such a way that any sort of NGU disaster does not bankrupt the parent utility ⁴³. It has been noted that Tepco (Tokyo Electric Power Company), the owner and operator of the Fukushima Daiichi plant, would have otherwise ceased to be financially viable without intervention and aid from the Japanese government ⁴³. Addressing new safety concerns and increasing safety measures in new NGU builds incurs greater capital costs for the new NGU build and retrofitting at such plants is typically viewed as being fiscally imprudent ⁴³.

With regard to fuel costs, there was a 20-year capital recovery period and a slightly more expensive annual cost of generation for a 400 MW A-NGCC unit running at a CF of 100% in North Carolina. While costs of natural gas and the relatively high penetration of natural gas-fired generation in North Carolina made NGU addition seem like a viable option, it should be noted that fuel costs can be locked in via contracts to guard against price volatility. Even with such contracts, prices do often vary and simply have floor and ceiling prices for the benefit of the fuel provider and the owner(s) of the A-NGCC. Only the 2014 average price of fuel was used to assess avoided fuel cost in this study. While unlikely, it is possible that fluctuations in price of fuel could alter dispatch order. In the event of sharp increase or decrease in natural gas prices, it is more likely that terms of a supply contract will need to be renegotiated with new ceiling and floor prices for the foreseeable future. The EIA reports natural gas statistics for the electric power sector separate from other prices for this reason, and due to the nature of natural monopolies often withholds that information because it inherently discloses the terms of that contract. The value of natural gas for mitigation as a cost-effective mitigation strategy would likely increase as A-NGCC units were dispatched to displace baseload coal generation. This also likely brings down the cost of A-NGCC

generation down as it displaces coal fuel costs, and at the very least cuts in the cost of decommissioning a coal unit.

It should be further noted that our results and description of feasibility of nuclear is only theoretical. While our findings suggested that initial NGU additions would have CFs at or around 100%, this is not likely to happen in reality over a given year due to the scheduled maintenance and refueling. It should be noted, however, that the addition of 1,117 MW units, such as those under construction in South Carolina, functioning at a 90% CF for a given hour would result in generation greater than that achieved by a 1,000 MW unit operating at a 100% CF for the same hour.

It should also be noted that such capital intensive projects require even large utilities to partner to jointly put forth the capital needed to fund the endeavor of building an NGU. Project finance plays a critical role in this, and the associated costs of risk mitigation that so often come in the form of brokered contracts were explicitly *not* included in the capital cost estimates provided by the EIA and subsequently used in this study³⁰. Insurance costs also serve as a fixed annual cost that will be incurred for each new built NGU. In addition, costs of fuel disposal are subject to change alongside changes in nuclear waste disposal policy. In addition, the siting of these facilities was not specified and transmission and distribution costs were not included in the scope of the study along with associated system import-export implications. Incorporation of dynamic day-by-day fuel pricing would uncover a more accurate picture of avoided fuel prices across the year and would have provided information on annual trends, especially if coupled with additional data from other prior years for which necessary data is available.

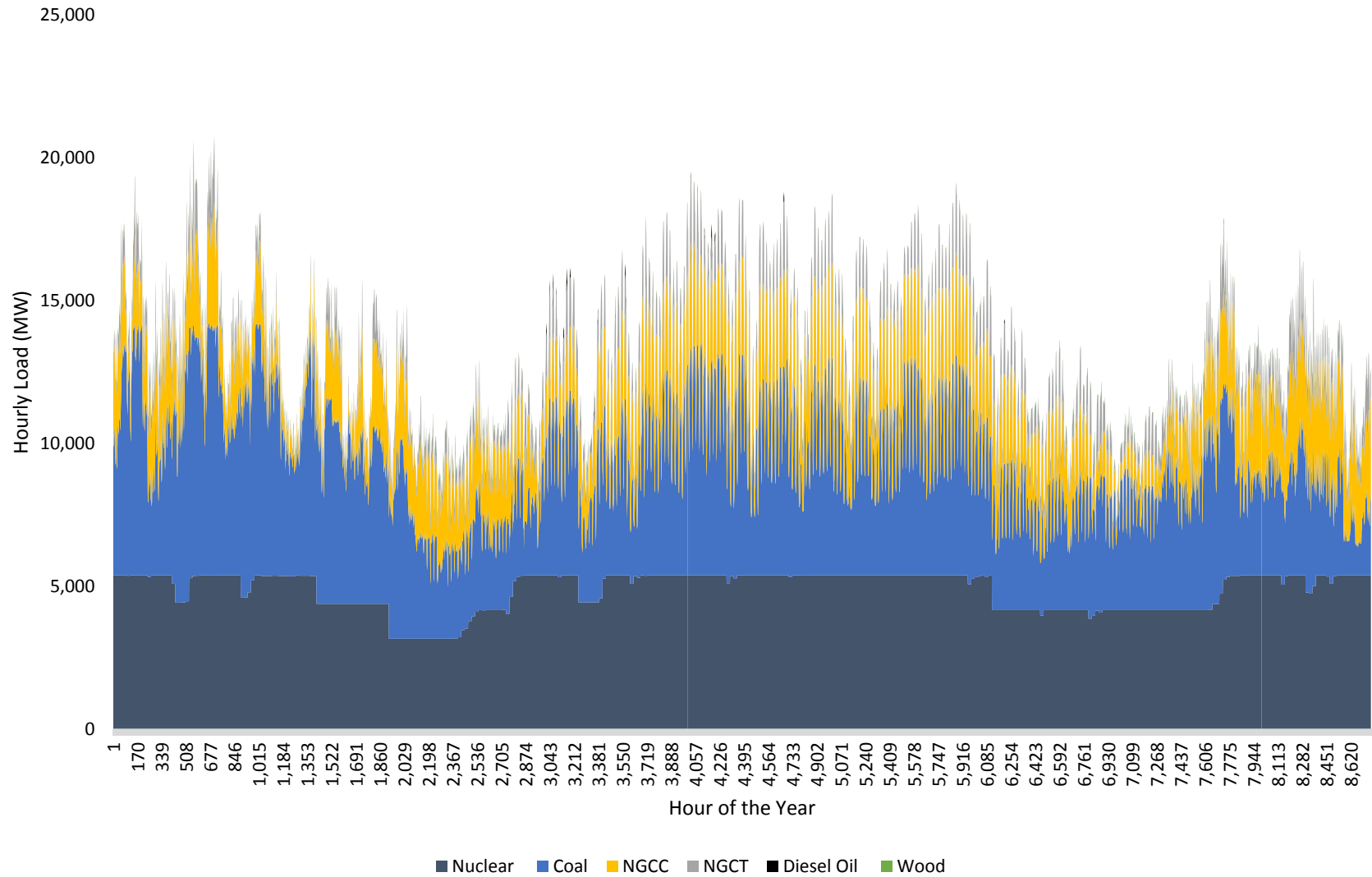
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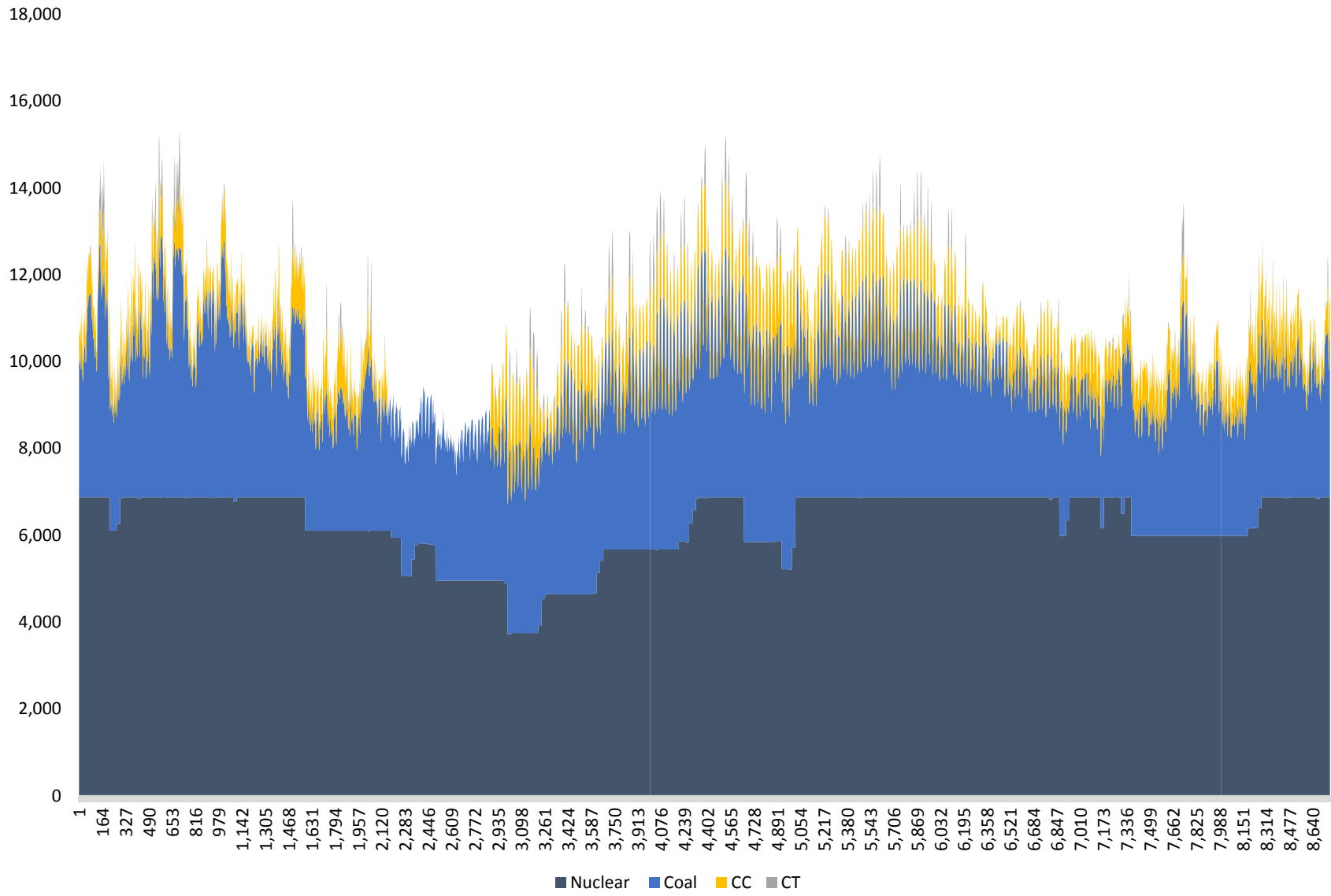
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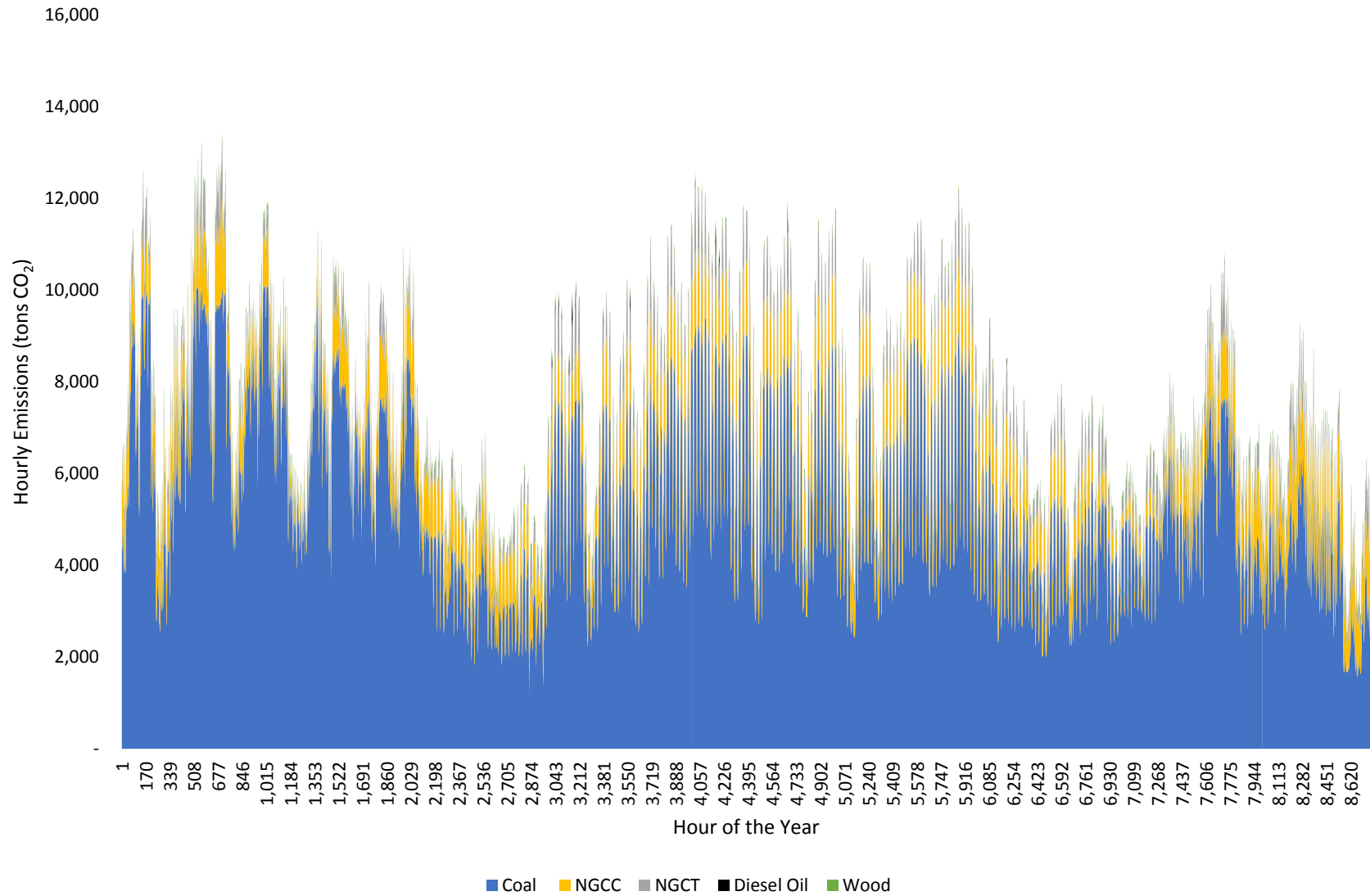
Appendix A- North Carolina Hourly 2014 CO₂ Generation by Type



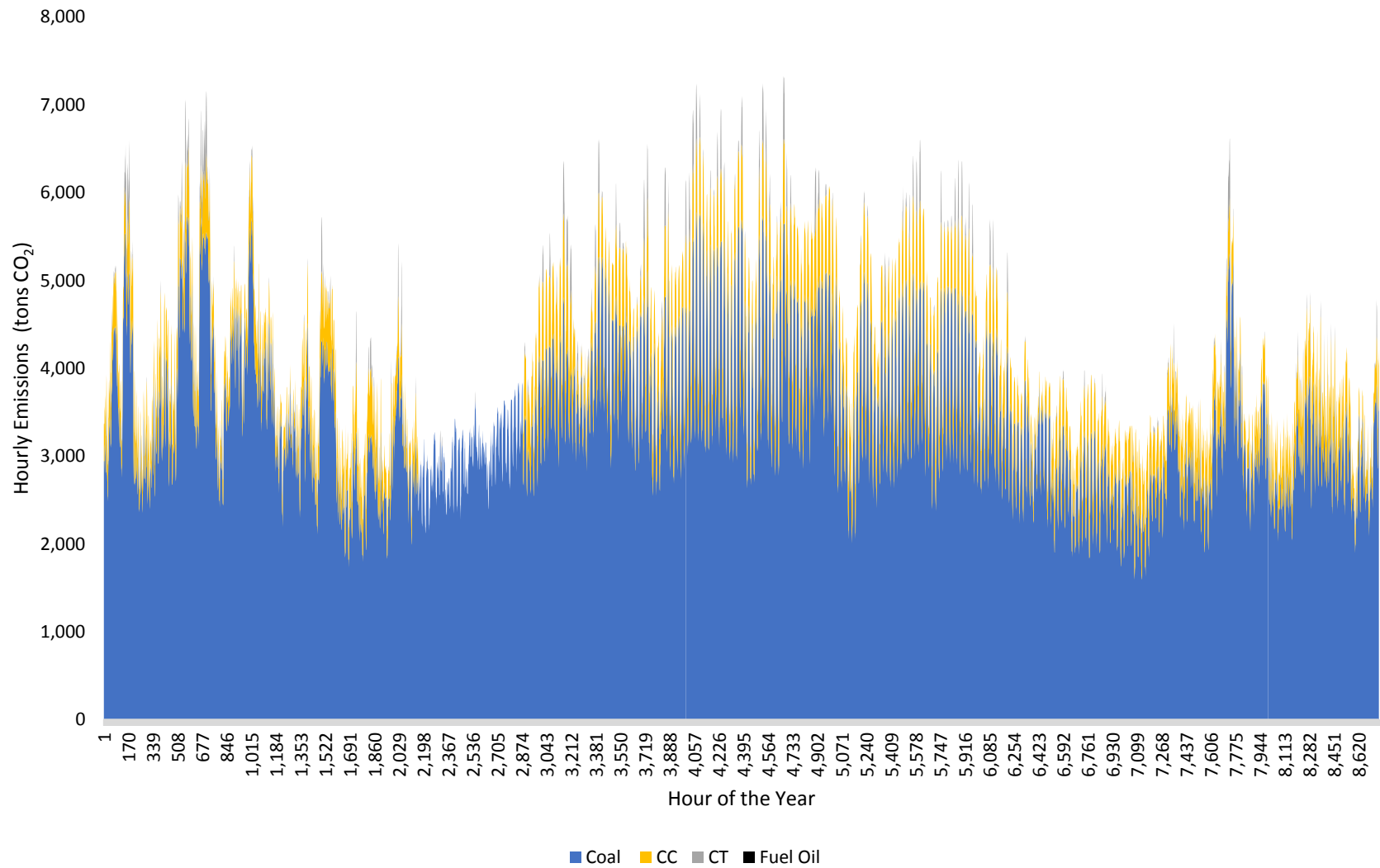
Appendix A- North Carolina Hourly 2014 CO₂ Generation by Type



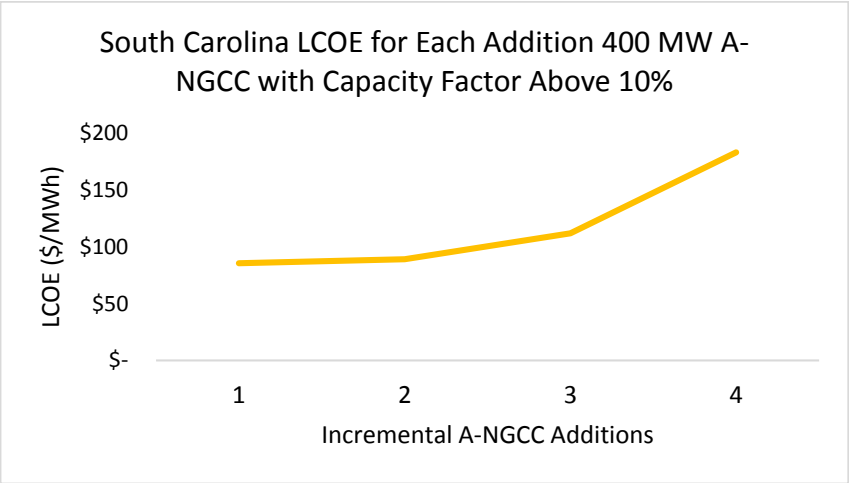
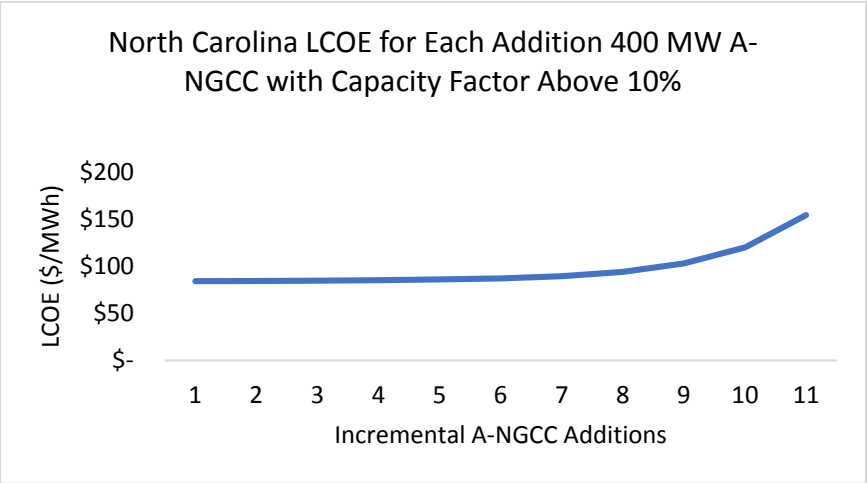
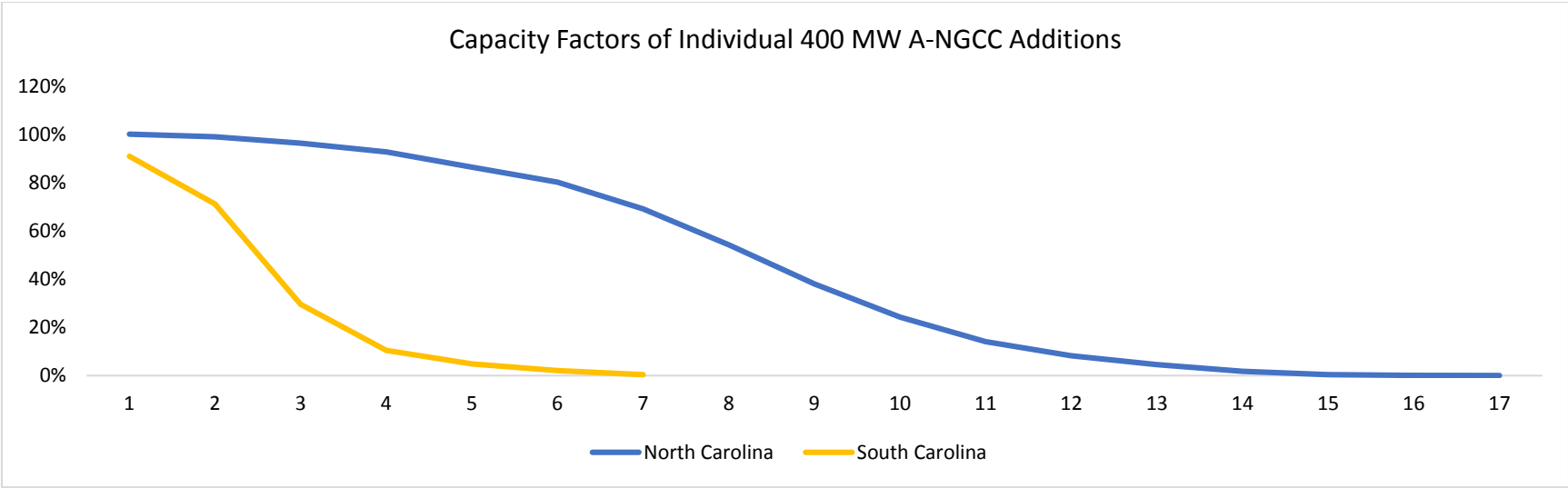
Appendix B- North Carolina Hourly 2014 CO₂ Emissions by Generation Type



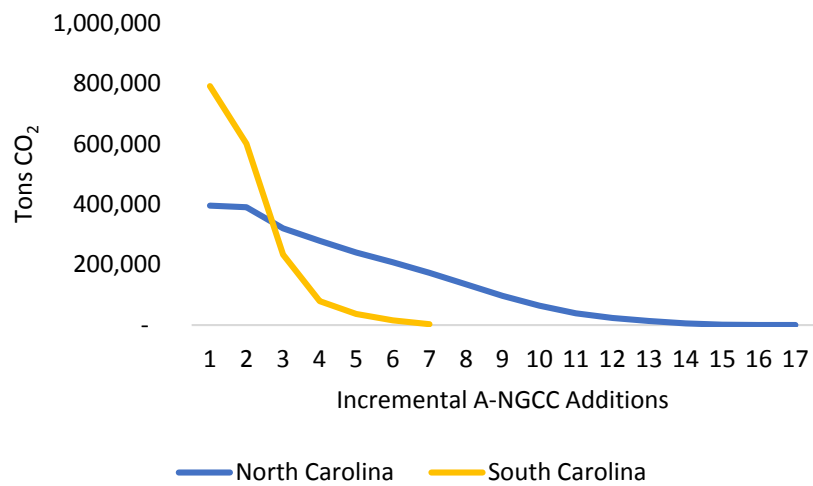
Appendix B- South Carolina Hourly 2014 CO₂ Generation by Type



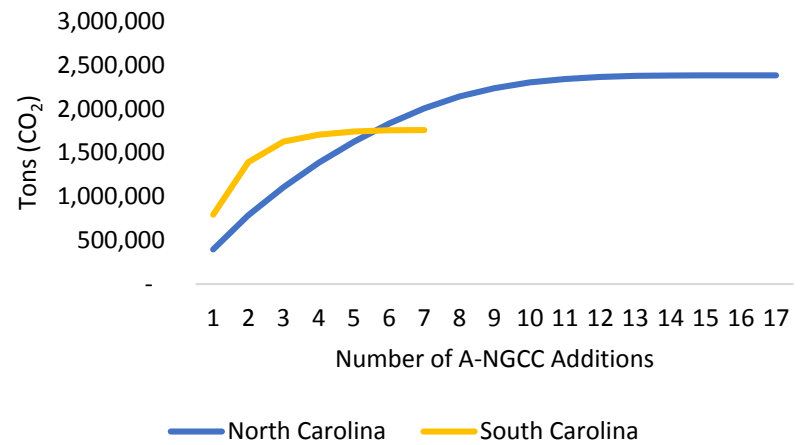
Appendix C- Advanced Natural Gas Combustion (A-NGCC) Cycle Graphs



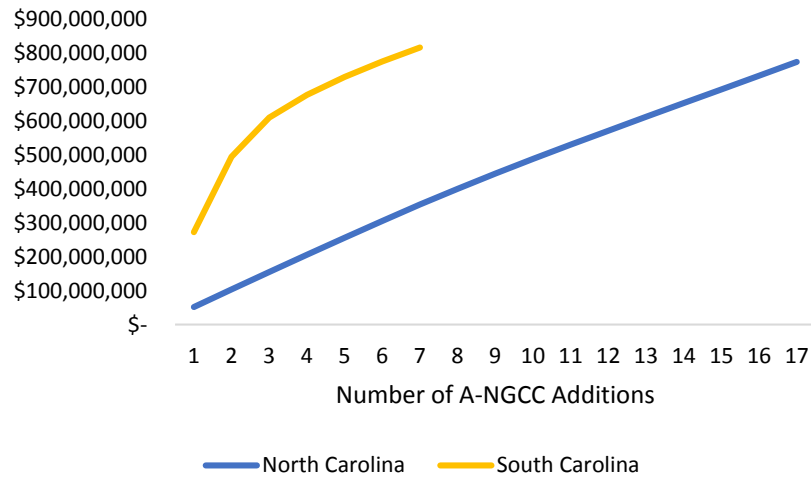
Avoided Emissions per 400 MW A-NGCC Unit



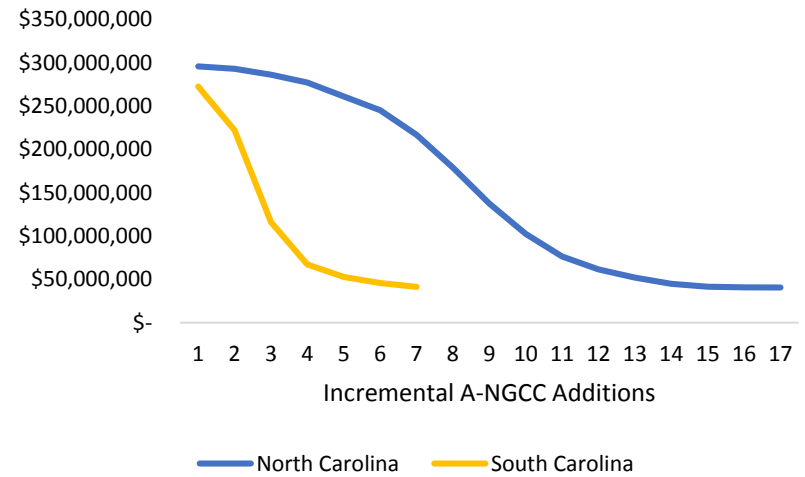
Cumulative Avoided Emissions with 400 MW A-NGCC



Cumulative Annual Cost of Generation per 400 MW A-NGCC Addition



Annual Cost of Generation per 400 MW A-NGCC Addition



Cost of Mitigation per Each 400 MW A-NGCC Unit (\$/ton CO₂)

