Capacity Expansion Planning Under the Risk of Hurricanes

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1. **Summary of Database for the North Carolina Energy Systems**

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**Figure 2.4:** Summary of Total Capacity for Existing Technologies Considering The Capacity Expansion Model. Capacity Decreases as Existing Technologies Retire.

1. **Detailed Database Construction For The North Carolina Energy System**

This section details the data used to construct the database for the North Carolina Energy System considered in the main manuscript. Throughout this section, costs are reported using 2020 U.S. dollars; however, inside the optimization tool [1], values are adjusted to the first year before the optimization (year 2022) using the Consumer Price Index (1.10 conversion rate) [2].

* 1. **Wind Speeds Data and Regionalization**

In this work, the Hazus FEMA model [3] is used to obtain statistical information regarding the recurrency of extreme winds in N.C. Illustrated in Figures 2.1 and 2.2 are the wind characteristics linked to events with recurrence intervals of 100 years and 1000 years, respectively.

|  |  |
| --- | --- |
|  |  |
| **Figure 2.1:** One Every100 Years Extreme Wind Speeds From Hazus (peak gust at 10m height) | **Figure 2.2:** One Every1000 Years Extreme Wind Speeds From Hazus (peak gust at 10m height) |

With the objective of modeling the influence of extreme winds on the electric power system infrastructure, it is important to understand that although the location of existing generators is known with certainty, which allows the assignment of specific wind speed statistics to those generators, the same cannot be said about future deployments. In capacity expansion models, the location of new deployments is usually defined from a pool of prespecified regions, where the number of regions significantly affects the computational complexity.

In this work, the N.C. state was divided into three equivalent regions (R1, R2, and R3), allowing the definition of an equivalent wind speed risk metric that is specific to each new technology and region of deployment (R1, R2, or R3). This procedure enables the simulation of the stochastic optimization model and the assignment of risk to new generations with reasonable computational cost. It is important to mention that this is a simplification and leads to not representing the full wind speed variability that may exist inside each of the three regions created.

Figure 2.3 shows the three regions mentioned above. Based on 1000-year wind data (Figure 2.2), region R1 is defined as any place in N.C. with wind speeds above 130mph, region R2 is defined as any place with wind speeds between 111-130mph, and region R3 is defined by wind speed below 111mph.

A map of the state of north carolina

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**Figure 2.3:** Regions for New Technology Deployment in NC With Different Risk Levels and Location of Existing Generators.

* 1. **Fragility and Loss Functions**

Fragility/Damage functions associate the probability of damage to equipment given certain extreme conditions, and loss functions associate the extreme event with the expected economic value lost for that equipment considering replacement or repair cost. When the fragility function refers to a system component that is critical to the device operation, like fragilities for the towers of wind turbines, its failure may be approximated as the total economic value of the device, as other device components would get damaged as a consequence of this component failure. Under these conditions, fragility functions were used in this work as a conservative approximation of the loss function for the technology under the extreme event.

In the literature, when the extreme condition is defined in terms of wind speeds, it can be referenced to different measurement heights and averaging periods (e.g., 3s, 1min, 10min); however, in this work, we follow the reference used by the FEMA – Hazus model [3] and report wind speeds at 10m height and 3s gust speeds, using conversion factors presented in [4, 3] when necessary.

For wind turbines, reference [5] investigates the construction of fragility curves for a 5MW offshore device (modeled as a Class I according to IEC 61400 [6]), defining the turbine buckling as the only mode of failure. For this reference, two modes of operation were considered: one where, due to power outages and no backup power available, the yaw motors of the wind turbines do not operate (no yawing case), and another where the yaw motors operate during the extreme event, these curves are shown in Figure 2.4 in green. In [5], it is also mentioned that the “no yawing case” is the more realistic scenario under hurricane conditions. Reference [7] examines both fragility and loss functions for 5MW offshore wind turbines across various substructures (monopile, tripod, jacket) and components (rotor, nacelle, tower). It evaluates different operational states, including normal operation, parked (yaw adjustment before the event), and emergency shutdown (yaw adjustment during the event). Figure 2.4, in black, illustrates the loss function and fragility curve for a monopile turbine's tower during emergency shutdowns, and also the loss function considering the device in a parked mode. Similarly, reference [8] investigates the fragility of 5MW offshore wind turbines under specific sea conditions in the Netherlands and the U.S., assuming the turbines do not yaw. The fragility of the turbine's tower structure in the U.S. context is shown in Figure 2.4 in red.

Regarding the literature on land-based wind turbines, reference [9] provides fragility curves for 3.3MW devices considering no yawing during extreme events, using turbine parameters representative of typical wind farms in Mexico, and showing results for the turbine's collapse (blue curve in Figure 2.4). Meanwhile, reference [10] uses a parametric approach to estimate the loss function for land-based wind turbines, using historical observations and individual component costs with their respective probability of failure at certain wind speeds, with good agreement with reference [9] for land-based devices.

Figure 2.4 illustrates the variety of fragility and loss functions for wind turbines, highlighting the significant variations due to differing modeling approaches. This underscores the ongoing complexity and uncertainty in defining these curves, which are influenced by both design and location. Despite these challenges, our study selects the parametric curve from [10] to estimate expected damages for land-based turbines, given its strong alignment with the findings of reference [9] and its simpler methodology, and for offshore turbines, we rely on reference [8], which accounts for sea state conditions typical in the U.S. and aligns well with both references [10] and [9].

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**Figure 2.4:** Fragility and Loss Function for Offshore and Land-Based Wind Turbines. F-Tower: Fragility Curve For Wind Turbine Tower; Tot. Loss: Loss Functions.

For solar generation, references [11] and [12] consider the determination of fragility curves for rooftop solar. Reference [12] investigates many different solar panel configurations and roof angles; however, for simplicity, we consider only three cases from this reference: the average behavior from 15-degree rooftops and the most and least vulnerable configurations. Figure 2.5 shows the fragility curves for these references in red and orange. As it is possible to see, there is good agreement between the different fragility curves; as such, we arbitrarily decided to use the data from [11], which has an intermediate behavior compared to the other curves. Regarding possible differences between the fragilities of rooftop and utility solar, we follow the approach of references [13, 11, 14], which argue that these fragilities can be approximated as similar as safety factors for operation in residential areas would be larger than those used in solar utility sites.

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**Figure 2.5:** Fragility Curves For Solar Energy Generation Technology.

For technologies such as substations, utility batteries, natural gas, coal, petroleum, biomass, hydro, and nuclear, the literature is not as detailed regarding the fragility of these technologies to hurricanes. However, other works [14, 15] have considered the use of standard fragility curves created by FEMA to represent general building categories as a way to model the vulnerability of these power system technologies to hurricanes.

In this work, we follow a similar approach of [14, 15]; however, instead of using the damage functions from the Hazus FEMA model, the loss functions were used. In Hazus, damage functions assign probabilities to different levels of physical damage to a building envelop components subject to hurricanes [16], whereas loss functions associate the percentage economic loss of the building infrastructure at different wind speeds. Damage functions are defined at different qualitative levels that associate the type of damage and its location, whereas loss functions are defined for different types of terrains (open, suburban, etc.).

In references [14, 15], moderate damage functions were considered, but no rationale was given to the use of such qualitative level. According to [16], moderate damage levels are characterized by major roof cover damage, moderate window breakage, minor roof sheathing failure, and some interior damage from water. As such, a moderate curve assigns at a given wind speed the probability that this type of damage happens. When applied to capacity expansion studies, fragility curves are used to estimate the percentage of existing capacity that must be reduced from damages due to hurricanes; therefore, we understand that the use of Hazus loss functions is more appropriate.

For utility battery technologies and substations, the Hazus loss function for steel-engineered commercial buildings with 1-2 stories (SECBL) was used. For natural gas, oil, coal, and biomass power plants, the loss function for steel-frame, engineered commercial buildings of 3–5 stories (SECBM) was used, and for hydro and nuclear powerplants, the loss function for concrete, engineered commercial buildings of 3–5 stories (CECBM) was used. All curves mentioned above were taken from Hazus considering an open terrain configuration and are shown in Figure 2.6 for comparison.

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**Figure 2.6:** Fragility Curves For Battery, Substations, Natural Gas, Coal, Biomass, Hydro and Nuclear Technologies.

Regarding the fragility of distribution systems to extreme winds, the literature is very extensive, with many works on the topic. Reference [17] investigated the fragility of wood and steel distribution poles during hurricane winds considering a class C4 pole (ANSI-O5.1 [18]); the fragility of new poles for this reference is shown in Figure 2.7 in red. Reference [19] estimated the fragility of wood poles to hurricanes considering a variety of pole classes, stating that class C5 was the most common in the Southeast U.S. Figure 2.7 shows in blue the fragility of 50-year-old C5 poles estimated by this reference (design parameter case).

References [20] and [17] also provide estimates of the fragilities of wood distribution poles due to hurricanes focusing on pole class C5. The estimates of [20] for new and 50-year-old poles are shown in Figure 2.7 in gray, and the estimates of [17] for 50-year-old poles are shown in green. Finally, Reference [21] makes a distinction between extreme winds from hurricanes and tornados and computes the fragility curves for C4 wood poles, which are shown in black.

As it is possible to see, there can be significant differences between the fragilities estimated by the references mentioned above, which are likely a consequence of the variety of mechanical and wind speed statistics considered in each study. In this work, we decided to approximate the fragility of distribution systems using the estimates from [17] (Solid-green) for new wood poles as it approximated well to other references on the lower wind speed spectrum, which is the region most likely to happen and consequently, most likely to affect the capacity expansion model results. It is important to mention that the probability represented in Figure 2.7 is for the failure of the distribution poles (buckling); however, the probability of failure of the distribution lines, which is larger than that of the poles alone, is not considered in this work for simplicity.

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**Figure 2.7:** Fragility Curves For Distribution Poles

As with distribution poles, the fragility of transmission systems to hurricanes has been investigated by multiple researchers. Reference [22] estimated the collapse probability of a typical 161kV- single circuit transmission tower (18m height) considering a series of synthetic hurricane wind speeds and directions for the region of Massachusetts-US; this curve is shown in green in Figure 2.8. Reference [23] investigated the fragility of a typical double-circuit tower 27.4m tall located in a hurricane-prone coastal area of the south U.S.; this curve is shown in blue in Figure 2.8. Reference [24] looked at the fragility of a variety of transmission towers typical for the Florida region, estimating a generalized fragility curve as shown in Figure 2.8 in orange. This reference also made comparisons with fragility curves estimated by a Quanta Technology’s report [25] which is also shown in Figure 2.8 (black) for comparison.

To accommodate variations from multiple references regarding the definition of fragility curves for transmission towers, this study adopts an averaged approach to these curves to estimate the potential damage to transmission systems under severe wind conditions. This averaged curve is depicted in red in Figure 2.8. As with the fragility of distribution systems, the damage to transmission infrastructure is associated only with the collapse of towers. We understand this is a conservative estimate as the damage to the line conductors and insulators is likely to happen earlier than the tower collapse. However, this avoids the need to discretize the costs of individual components, simplifying the analysis.

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**Figure 2.8:** Fragility Curves For Transmission Towers

Finally, Figure 2.9 offers a comprehensive summary of the fragility functions utilized in our analysis for evaluating damage to the electrical power system infrastructure. This section has underscored the considerable uncertainty inherent in the formulation of these curves. Consequently, the curves depicted in Figure 2.9 should not be viewed as definitive. They are the result of an extensive review of multiple studies, aiming to integrate a wide range of perspectives and methodologies. This effort aimed to capture the most representative fragility functions, thereby enhancing the robustness and accuracy of our damage estimations under varying extreme weather conditions. Recognizing the provisional nature of these curves, future research must prioritize the detailed compilation and critical examination of fragility curve variations. This will enable their more effective application in power systems studies, significantly improving the precision, reliability, and resilience of power infrastructure in responding to extreme weather events and advancing the development of more effective mitigation strategies.

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**Figure 2.9:** Summary of Fragility Curves Used in the Capacity Expansion Model for the Computation of Damage to the Power System Infrastructure.

* 1. **Energy Demand**

From the EIA 861 form [26], historical electricity sales data is available for the state of N.C. from before 2021, and from the Duke Energy Carbon Plan 2023 [27] (Appendix F), forecasts for energy sales by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) are available until 2037. As more than 60% of the total existing electricity capacity in N.C. belongs to Duke Energy [28], the percentage load forecast increases from the combined DEC and DEP systems are used to project the future load sales on the NC until 2037, and the average annual growth rate from 2033-2037 is used to extend the forecast until 2050. Table 1 shows values for load sales from the references mentioned above and the estimates made for N.C. It is important to mention that load sales estimates from Duke Energy account for load reductions due to energy efficiency and distributed solar generation.

**Table 1:** Load Sales Estimates For DEC, DEP, and N.C.

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Year** | **DEC Load**  **[GWh]** | **DEP Load**  **[GWh]** | **DEC+DEP Load [GWh]** | **DEC+DEP Ratio of Increase From 2021** | **N.C. Net Load [GWh]** |
| 2021 | 86,880 | 60,139 | 147,019 | 1 | 135,693 |
| 2022\* | - | - | - | - | - |
| 2023 | 91,983 | 64,259 | 156,242 | 1.063 | 144,205 |
| 2024 | 92,304 | 64,636 | 156,940 | 1.067 | 144,850 |
| 2025 | 92,349 | 64,525 | 156,874 | 1.067 | 144,789 |
| 2026 | 92,667 | 64,408 | 157,075 | 1.068 | 144,974 |
| 2027 | 93,100 | 64,486 | 157,586 | 1.072 | 145,446 |
| 2028 | 93,815 | 64,752 | 158,567 | 1.079 | 146,351 |
| 2029 | 94,629 | 65,051 | 159,680 | 1.086 | 147,379 |
| 2030 | 95,454 | 65,376 | 160,830 | 1.094 | 148,440 |
| 2031 | 96,466 | 65,795 | 162,261 | 1.104 | 149,761 |
| 2032 | 97,447 | 66,391 | 163,838 | 1.114 | 151,216 |
| 2033 | 98,372 | 66,937 | 165,309 | 1.124 | 152,574 |
| 2034 | 99,313 | 67,570 | 166,883 | 1.135 | 154,027 |
| 2035 | 100,289 | 68,254 | 168,543 | 1.146 | 155,559 |
| 2036 | 101,284 | 69,026 | 170,310 | 1.158 | 157,190 |
| 2037 | 102,343 | 69,817 | 172,160 | 1.171 | 158,897 |
| Avg. Annual Growth  (2033-3037) | 0.85% | 0.79% | 0.82% | - | 0.82% |

\*Not Available from EIA 861-2022

From the projections mentioned above, it is important to take into consideration the effect that distributed solar energy generation has on the net load, as this effect may change the load distribution in systems where distributed solar energy generation is significant. In such cases, it is preferable to simulate the capacity expansion model using the total load, which can be approximated by adding the distributed solar energy generation projections to the data of Table 1. This approximation assumes that the distributed solar energy-generating units indirectly consume at least the energy they generate or more (no solar energy excess over the year).

Table 2 shows the residential and commercial solar energy generation projections derived from appendixes D and F of the Duke Energy Carbon Plan 2023 [27]. Unfortunately, [27] does not detail its solar projections for all years between 2022-2037. However, as this work adopts a simplified time discretization in its capacity expansion simulations, considering only the periods {2023, 2025, 2030, 2035, 2040, 2045, and 2050}, a simple interpolation of Table 2 was used to estimate solar energy projections from 2023 to 2035, and for the years after 2037 solar growth rates for the continental U.S. from the AEO 2023 [29] (reference case) were applied to the 2037 duke energy estimates. These results are shown in Table 3 for the Duke Energy systems, which were scaled for N.C. using a factor of 0.922 (Table 1 ratio of 2021 estimates of net load between N.C. and DEC+DEP).

**Table 2:** Projection of Distributed Solar Energy Generation on DEC and DEP

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Residential Solar Energy Generation**  **[GWh]** | | | **Commercial Solar Energy Generation**  **[MWh]** | | | **DEC+DEP Total Distributed Solar [MWh]** |
| **DEC** | **DEP** | **Total** | **DEC** | **DEP** | **Total** |
| 2022 | 223.447 | 138.325 | 361.772 | 86.816 | 44.755 | 131.571 | 493.343 |
| 2023 | 266.371 | 173.101 | 439.472 | 96.407 | 51.796 | 148.203 | 587.675 |
| 2030 | 577.702 | 327.493 | 905.195 | 179.008 | 106.847 | 285.855 | 1,191.050 |
| 2037 | 1,392.526 | 956.027 | 2,348.553 | 330.399 | 147.422 | 477.821 | 2,826.374 |

**Table 3:** Distributed Solar Energy Generation at “DEC+DEP” and N.C. and Total Load Estimations

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **DEC+DEP** | | | | | | **NC\*\*** | | |
| **Solar Residential** | | **Solar Commercial** | | **Net Load**  **[GWh]** | **Total Load:**  **(Net Load + Dist. Solar)**  **[GWh]** | **Generation from Solar Residential**  **[GWh]** | **Generation from Solar Commercial**  **[GWh]** | **Total Load**  **(Net Load + Dist. Solar)**  **[GWh]** |
| **Generation [GWh]** | **AEO 23 Increase from 2037 Values\*** | **Generation [GWh]** | **AEO 23 Increase from 2037 Values\*** |
| 2023 | 439 | - | 148 | - | 156,242 | 156,830 | 406 | 137 | 144,748 |
| 2025 | 573 | - | 188 | - | 156,874 | 157,634 | 528 | 173 | 145,490 |
| 2030 | 905 | - | 286 | - | 160,830 | 162,021 | 835 | 264 | 149,539 |
| 2035 | 1,936 | - | 423 | - | 168,543 | 170,902 | 1,787 | 390 | 157,736 |
| 2040 | 2,750 | 1.17 | 529 | 1.11 | 176,406 | 179,685 | 2,539 | 488 | 165,843 |
| 2045 | 3,582 | 1.52 | 581 | 1.22 | 183,717 | 187,880 | 3,306 | 537 | 173,407 |
| 2050 | 4,593 | 1.96 | 618 | 1.29 | 191,330 | 196,542 | 4,239 | 570 | 181,400 |

\*See Table 2 for total solar projection during 2037.

\*\*Conversion from Duke to total load using a factor of 0.923

In terms of the load distribution, hourly demand for DEC and DEP from 2016-2019 was obtained from the EIA 930 reports [30] and used to define an average load distribution for N.C.; this time interval was chosen to avoid biases due to the COVID-19 pandemic. Figure 2.10 shows in black the demand distribution considered in this work. In this case, data from EIA 930 was not ajusted to account for distributed solar energy generation as was done for the total load since the current distributed solar generation is around 0.3% of the total electricity demand, and back in 2016-2019 this ratio would likely be much smaller.

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**Figure 2.10:** Demand Distribution From DEP+DEC From 2016 to 2019 (Demand Distribution Used for NC)

Finally, since this work considered the segmentation of N.C. in multiple regions (R1, R2, and R3), as explained in the previous sections, the total load shown in Table 3 (last column) was distributed based on the percentage of the total population at each region, and in this case, no changes were assumed to the seasonal/hourly load distribution (Figure 2.10). Using the 2020 census [31], the ratios considered were 7.02%, 12.98%, and 80.00% for regions R1, R2, and R3, respectively.

* 1. **Transmission and Distribution**

The transmission system was modeled in this work considering two types of infrastructure: one for transferring electricity inside each subregion and another for transferring electricity between subregions. This is only a modeling consideration, as in practice, regions R1, R2, and R3 are all fully integrated with multiple transmission lines on their borders. For distribution, each of the three NC regions has its own distribution system with no direct connection between regions.

First an initial simulation of the capacity expansion model up to the 2023, was performed to determine the transmission/distribution system capacity to operate the current NC power system; the results of this simulation are shown in Table 5.

**Table 4:** Existing Capacity for Transmission and Distribution in the NC Power System.

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Technology** | **Region** | | | | | |
| **R1** | **R2** | **R3** | **R1-R2** | **R1-R3** | **R2-R3** |
| Distribution Existing Capacity [GW] | 1.673 [GW] | 3.092 [GW] | 19.056 [GW] | - | - | - |
| Transmission Existing Capacity [GW] | 2.005 [GW] | 3.181 [GW] | 19.605 [GW] | 0.889 [GW] | 0.7128 [GW] | 0.5401 [GW] |

In terms of the transmission system, estimates of installed miles per voltage level were obtained from the 2022 Duke Energy Carbon Plan Appendix-P [32] for Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), and costs per MW-Mile and average circuit capacities for different voltage levels were obtained from the NREL ReEDS model [33]. With the information mentioned above, the total capital cost of the transmission system infrastructure on the DEP/DEC system was determined by multiplying the total average circuit capacity by its total length and average price (Table 5). Finally, the total transmission system cost for NC was estimated by multiplying the DEP/DEC costs by 92.3%, which corresponds to the ratio between DEP/DEC load and the NC load (see Section 2.3), and this value was divided by the total transmission system capacity of Table 4 (26.9GW) to determine the NC transmission system CAPEX as 859M$/GW, consistent with the range estimated by other works [34]. For the operational costs, a value of 2% of CAPEX (17M$/GWyr) was assumed based on [35, 36].

**Table 5:** Data Used to Estimated CAPEX for The NC Transmission System

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Circuit Voltage** | **DEC+DEP** [32, 33] | | | | **NC** |
| **Total Miles** | **Average Circuit Capacity [MW]** | **CAPEX**  **[$/MW-Mile]**  **(2020 USD)** | **Total CAPEX**  **[M$]**  **(2020 USD)** | **Total CAPEX**  **[M$]**  **(2020 USD)** |
| 44-69 KV | 2885 | 102 | 8140 | 2395.2 | 2210.8 |
| 100-199 KV | 9417 | 205 | 4868 | 9398.2 | 8674.6 |
| 230 KV | 6089 | 400 | 3974 | 9678.1 | 8932.9 |
| 500+ KV | 868 | 1500 | 2742 | 3569.9 | 3295.0 |
| Total Sum | 19259 | - | - | 25041.5 | 23113.3 **(859M$/GW)\*** |

\*Estimated by dividing the total CAPEX by the estimated transmission system capacity in NC (26.9GW)

According to EIA [37], about 40% of the total capital expenditures on transmission systems between 2015-2019 were related to substation costs; as such, this work follows the same percentages and assumes that from the total 859M$/GW of transmission capital expenditures, 60% (515.4M$/GW) would be subjected to the fragility of transmission towers and 40% (343.6M$/GW) would be subjected to the fragility of substations (see fragility curve in Figure 2.9).

Regarding the NC distribution system, according to EIA [38], about 47% of the total annualized costs in the distribution system went to operational costs between 2015 and 2019, and according to the EIA AEO-23 [29], distribution is estimated to cost about 2.38 cents/kWh (2020 USD) in 2023. For NC, this means that distribution should cost around 3,449 [M$/yr], of which 1,619 [M$/yr] would go for OPEX and 1,830 [M$/yr] for CAPEX. Assuming that OPEX corresponds to around 7% of total capital investments in distribution systems [38], it is possible to estimate at 23,128[M$] the current value of the NC distribution system. From the simulation of our capacity expansion model, we found that 23.8GW of existing distribution system capacity would be necessary for the operation of our NC model, which leads to 972[M$/GW] in CAPEX, and 68[M$/GWyr] in OPEX, the costs values used in our capacity expansion model.

Finally, from [39, 40], we considered that 20% of the distribution energy infrastructure is underground and would not be damaged by hurricanes, also considering that this percentage would not change thoughout the simulation period (a simplifying assumption). We do not consider this type of situation for the transmission system as only a very small percentage of it is estimated to be underground [41], less than 1%.

* 1. **Energy Import/Export**

According to EIA [42], North Carolina has been a net importer of electricity for more than 30 years, importing about 10.25% of its electricity from neighboring states in the years 2018 to 2021. Due to limitations in data availability regarding the evolution of energy interchange, this work follows a similar approach of [43], which assumes that all power generated in North Carolina is used in the state and the remaining electricity demand is met by imported electricity. Furthermore, we enforce maximum limits for energy import as 10.25% of the demand for each simulated year (as done by [43]) and minimum imports that start equal to the maximum demand in 2023 and decrease 1% per year, which enforce more realistic behaviors on energy imports.

For investment costs and fixed costs of creating import infrastructure, we used the analysis made in Section 2.3, assuming 859M$/GW for investment costs and 17M$/GWyr for fixed costs, and for the variable costs of importing electricity, we use projections from EIA AEO-23 [29] on electricity prices for electricity generation in the SERC-East region. Initial interstate transmission system capacities are determined by running our capacity expansion model until the year 2023 (present), estimating how much capacity is needed to operate the current system. Maximum capacity growths were also enforced, assuming a maximum increase of 0.82% per year, the same rate estimated in Table 3 for the terminal load growth. Table 6 summarises the parameters used to model energy imports.

Particularly for energy import, no fragility curves were assumed for this infrastructure due to the difficulties in estimating the full extent of this type of transmission system (location and capacity wise).

**Table 6:** Parameters Used to Model Energy Import in the NC Capacity Expansion Model

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Energy Import Parameters** | **Year** | | | | | | | **References** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| Investment Cost [M$/GW] | 859 | 859 | 859 | 859 | 859 | 859 | 859 | Section 2.4 |
| Fixed Cost [M$/GWyr] (2020 USD) | 17 | 17 | 17 | 17 | 17 | 17 | 17 | [44] |
| Variable Cost [$/MWh] (2020 USD) | 62.4 | 60.1 | 48.4 | 49.1 | 51.7 | 49.9 | 50.3 | [29] |
| Max Activity [GWh/yr] | 14,837 | 14,913 | 15,328 | 16,168 | 16,999 | 17,774 | 18,594 | 10.25% of Demand |
| Min Activity [GWh/yr] | 14,837 | 14,540 | 13,798 | 13,056 | 12,314 | 11,573 | 10,830 | Gradually Decrease 1% per Year |
| Max Capacity [GW] -R1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2023 ESOM Run\* and 0.82% Max Annual Increase |
| Max Capacity [GW] -R2 | 1.83 | 1.86 | 1.94 | 2.02 | 2.10 | 2.19 | 2.28 |
| Max Capacity [GW] -R3 | 4.68 | 4.75 | 4.95 | 5.16 | 5.37 | 5.60 | 5.83 |

\*Estimated by running our Energy System Optimization Model (ESOM) until the year 2023.

* 1. **Technologies**

Tables 2.1 and 2.2 describe the existing and new energy generation technologies considered in our simulations, and Table 2.3 describes the non-energy generation technologies.

**Table 2.1:** Existing Generation Technologies Represented in The Model

|  |  |
| --- | --- |
| **Technology Code** | **Description** (Following EIA 860 Nomenclature) [28] |
| AB\_ST\_EXISTING | Steam Turbine Using Agricultural By-Products |
| BIT\_ST\_EXISTING | Steam Turbine Using Bituminous Coal |
| BLQ\_ST\_EXISTING | Steam Turbine Using Black Liquor |
| DFO\_CC\_EXISTING | Combined Cycle Combustion Turbine Using Petroleum |
| DFO\_GT\_EXISTING | Combustion Turbine Using Petroleum |
| DFO\_IC\_EXISTING | Internal Combustion Engine Using Petroleum |
| LFG\_GT\_EXISTING | Combustion Turbine Using Landfill Gas |
| LFG\_IC\_EXISTING | Internal Combustion Engine Using Landfill Gas |
| MWH\_BA1H\_EXISTING | Battery Storage- 1h |
| MWH\_BA2H\_EXISTING | Battery Storage- 2h |
| NG\_CC\_EXISTING | Combined Cycle Combustion Turbine Using Natural Gas |
| NG\_GT\_EXISTING | Combustion Turbine Using Natural Gas |
| NG\_ST\_EXISTING | Steam Turbine Using Natural Gas |
| NUC\_ST\_EXISTING | Nuclear Turbine |
| OBG\_IC\_EXISTING | Internal Combustion Engine Using Other Biomass Gas |
| SUN\_PV\_EXISTING | Solar Photovoltaic - Utility |
| WAT\_HY\_EXISTING | Conventional Hydroelectric |
| WAT\_PS\_EXISTING | Hydroelectric Pumped Storage |
| WDS\_ST\_EXISTING | Steam Turbine Using Wood Waste |
| WH\_ST\_EXISTING | Steam Turbine Using Waste Heat |
| WND\_WT\_EXISTING | Onshore Wind Turbine |

**Table 2.2:** New Generation Technologies Represented in The Model

|  |  |
| --- | --- |
| **Technology Code** | **Description** |
| BATT\_2H\_NEW | Battery Storage 2h – Utility Scale (NREL ATB 2022 Technology) [45] |
| BATT\_4H\_NEW | Battery Storage 4h – Utility Scale (NREL ATB 2022 Technology) [45] |
| BATT\_6H\_NEW | Battery Storage 6h – Utility Scale (NREL ATB 2022 Technology) [45] |
| BATT\_8H\_NEW | Battery Storage 8h – Utility Scale (NREL ATB 2022 Technology) [45] |
| BIOMASS\_CC90\_NEW | Generation From Biomass With 90% Carbon Capture (Technology from NREL ReEDS model Using BECC-mod) [33] |
| BIOMASS\_NEW | Generation From Biomass (NREL ATB 2022 Technology) [45] |
| COAL\_95CC\_NEW | Generation From Coal With 95% Carbon Capture (NREL ATB 2022 Technology) [45] |
| COAL\_99CC\_NEW | Generation From Coal With 99% Carbon Capture (NREL ATB 2022 Technology) [45] |
| COAL\_NEW | Generation From Coal (NREL ATB 2022 Technology) [45] |
| NG\_F-FRAME\_CC\_95CC\_NEW | Combined Cycle Natural Gas Turbine F-Frame With 95 % of Carbon Capture (NREL ATB 2022 Technology) [45] |
| NG\_F-FRAME\_CC\_97CC\_NEW | Combined Cycle Natural Gas Turbine F-Frame With 97 % of Carbon Capture (NREL ATB 2022 Technology) [45] |
| NG\_F-FRAME\_CC\_NEW | Combined Cycle Natural Gas Turbine F-Frame (NREL ATB 2022 Technology) [45] |
| NG\_F-FRAME\_CT\_NEW | Natural Gas Combustion Turbine F-Frame - Simple Cycle (NREL ATB 2022 Technology) [45] |
| NG\_H-FRAME\_CC\_95CC\_NEW | Combined Cycle Natural Gas Turbine H-Frame With 95 % of Carbon Capture (NREL ATB 2022 Technology) [45] |
| NG\_H-FRAME\_CC\_97CC\_NEW | Combined Cycle Natural Gas Turbine H-Frame With 97 % of Carbon Capture (NREL ATB 2022 Technology) [45] |
| NG\_H-FRAME\_CC\_NEW | Combined Cycle Natural Gas Turbine H-Frame (NREL ATB 2022 Technology) [45] |
| NUCLEAR-AP1000\_NEW | Nuclear Generation Using AP1000 PWR (NREL ATB 2022 Technology) [45] |
| NUCLEAR-SMR\_NEW | Small Modular Nuclear Reactor (NREL ATB 2022 Technology) [45] |
| PV-COMMERCIAL\_NEW | Commercial Solar P.V. (NREL ATB 2022 Technology) [45] |
| PV-RESIDENTIAL\_NEW | Residential Solar P.V. (NREL ATB 2022 Technology) [45] |
| PV-UTILITY\_NEW | Utility Solar P.V. (NREL ATB 2022 Technology) [45] |
| WAT\_HY\_NEW | Conventional Hydroelectric (NREL ATB 2022 Technology) [45] |
| WAT\_PS\_NEW | Hydroelectric Pumped Storage (NREL ATB 2022 Technology) [45] |
| WIND-LAND-C8\_NEW | Onshore Wind Turbine Class 8 From NREL ATB 2022 (NREL ATB 2022 Technology) [45] |
| WIND-OFFSHORE-C6\_NEW | Offshore Wind Turbine Class 6 From NREL ATB 2022 (NREL ATB 2022 Technology) [45] |

**Table 2.3:** Non-Generation Technologies Represented in The Model

|  |  |
| --- | --- |
| **Technology Code** | **Description** |
| CO2\_STORAGE | CO2 Storage |
| DISTRIBUTION | Energy Distribution |
| FT\_BIOMASS | Fuel for Generation Technologies That Use Biomass |
| FT\_COAL | Fuel for Generation Technologies That Use Coal |
| FT\_NG | Fuel for Generation Technologies That Use Natural Gas |
| FT\_NUCLEAR | Fuel for Nuclear Generation Technologies |
| FT\_PETROLEUM | Fuel for Generation Technologies That Use Petroleum |
| TRANSMISSION\_INTERREGIONAL | Transmission Between Different Regions |
| TRANSMISSION\_REGIONAL | Transmission In the Same Region |

* 1. **Existing Capacity**

Data from existing generation capacity comes from the EIA-860M reports [28]. Figure 2.1 shows the vintage (operational year) of each existing technology on the N.C. system and its corresponding capacity. On the left legend, the total existing capacity is shown in parathesis.

A graph of different colored lines

Description automatically generated

**Figure 2.1:** Total Existing Capacity on the N.C. Power System by Different Operational Years (Vintages). The System Has 39GW of Total Capacity (end 2022) According to The EIA-860M reports [28].

* 1. **Lifetime Tech and Loan**

The default lifetimes and loan periods of the technologies considered in our models are detailed in Tables 2.4, 2.5, and 2.6 with their corresponding references.

**Table 2.4:** Default Technologies Lifetime For Existing Generation Technologies

|  |  |  |
| --- | --- | --- |
| **Technology Code** | **Lifetime Tech** | |
| **Years** | **Reference** |
| AB\_ST\_EXISTING | 27 | Weighted Average of Past Retirements on U.S. [28] |
| BIT\_ST\_EXISTING | 56 | Weighted Average from DEC/DEP in IRPs [46, 47] |
| BLQ\_ST\_EXISTING | 55 | Weighted Average of Past Retirements on NC [28] |
| DFO\_CC\_EXISTING | 58 | Weighted Average of Past Retirements on NC [28] |
| DFO\_GT\_EXISTING | 69 | Weighted Average from DEC/DEP in IRPs [46, 47] |
| DFO\_IC\_EXISTING | 36 | Weighted Average of Past Retirements on the East Coast [28] |
| LFG\_GT\_EXISTING | 20 | Weighted Average Retirement on the East Coast [28] |
| LFG\_IC\_EXISTING | 16 | Weighted Average Retirement on the East Coast [28] |
| MWH\_BA1H\_EXISTING | 15 | From NREL ReEDS [33] |
| MWH\_BA2H\_EXISTING | 15 | From NREL ReEDS [33] |
| NG\_CC\_EXISTING | 37 | Weighted Average from DEC/DEP in IRPs [46, 47] For NG CA and CT |
| NG\_GT\_EXISTING | 42 | Weighted Average from DEC/DEP in IRPs [46, 47] |
| NG\_ST\_EXISTING | 53 | Weighted Average Retirement on the East Coast [28] |
| NUC\_ST\_EXISTING | 59 | Weighted Average from DEC/DEP in IRPs [46, 47] |
| OBG\_IC\_EXISTING | 15 | Weighted Average of Past Retirements on U.S. [28] |
| SUN\_PV\_EXISTING | 30 | From NREL ReEDS [33] |
| WAT\_HY\_EXISTING | 109 | Weighted Average from DEC/DEP in IRPs [46, 47] for WAT\_HY |
| WAT\_PS\_EXISTING | 109 |
| WDS\_ST\_EXISTING | 50 | From NREL ReEDS [33] for Biopower |
| WH\_ST\_EXISTING | 33 | Weighted Average of Past Retirements on U.S. [28] |
| WND\_WT\_EXISTING | 30 | From NREL ReEDS [33] |

In Table 2.4, “weighted average” refers to the weighted average of the technology lifetime using reported device capacities. In this table, when reference [28] is used if the total capacity of past technology retirements in N.C. is below 100MW, the average for the entire US-East Coast is used, and if the total capacity for existing data is still below 100MW, data of the whole U.S. is used.

**Table 2.5:** Default Technologies Lifetime and Loan Periods Times For New Generation Technologies

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Technology Code** | **Lifetime Tech** | | **Loan Period (Recovery Period)** | |
| **Years** | **Reference** | **Years** | **Reference** |
| BATT\_2H\_NEW | 15 | From NREL ReEDS [33] | 15 | From NREL ReEDS [33] |
| BATT\_4H\_NEW | 15 | From NREL ReEDS [33] | 15 | From NREL ReEDS [33] |
| BATT\_6H\_NEW | 15 | From NREL ReEDS [33] | 15 | From NREL ReEDS [33] |
| BATT\_8H\_NEW | 15 | From NREL ReEDS [33] | 15 | From NREL ReEDS [33] |
| BIOMASS\_CC90\_NEW | 50 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| BIOMASS\_NEW | 50 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| COAL\_95CC\_NEW | 65 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| COAL\_99CC\_NEW | 65 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| COAL\_NEW | 65 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_F-FRAME\_CC\_95CC\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_F-FRAME\_CC\_97CC\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_F-FRAME\_CC\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_F-FRAME\_CT\_NEW | 50 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_H-FRAME\_CC\_95CC\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_H-FRAME\_CC\_97CC\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NG\_H-FRAME\_CC\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NUCLEAR-AP1000\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| NUCLEAR-SMR\_NEW | 60 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| PV-COMMERCIAL\_NEW | 30 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| PV-RESIDENTIAL\_NEW | 30 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| PV-UTILITY\_NEW | 30 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| WAT\_HY\_NEW | 109 | Average from DEC/DEP in IRPs [46, 47] for WAT\_HY | 20 | From NREL ReEDS [33] |
| WAT\_PS\_NEW | 109 | 20 | From NREL ReEDS [33] |
| WIND-LAND-C8\_NEW | 30 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |
| WIND-OFFSHORE-C6\_NEW | 30 | From NREL ReEDS [33] | 20 | From NREL ReEDS [33] |

**Table 2.6:** Default Technologies Lifetime and Loan Periods For Non-Generation Technologies

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Technology Code** | **Lifetime Tech** | | **Loan Period (Recovery Period)** | |
| **Years** | **Reference** | **Years** | **Reference** |
| DISTRIBUTION | 60 |  | 20 |  |
| TRANSMISSION\_INTERREGIONAL | 60 |  | 20 |  |
| TRANSMISSION\_REGIONAL | 60 |  | 20 |  |
| CO2\_STORAGE\* | NA\* | | | |
| FT\_BIOMASS\* | NA\* | | | |
| FT\_COAL\* | NA\* | | | |
| FT\_NG\* | NA\* | | | |
| FT\_NUCLEAR\* | NA\* | | | |
| FT\_PETROLEUM\* | NA\* | | | |

\*We do not consider investment costs for this technology (all costs for it are variable or fixed); as such, the lifetime of the tech and its loan period can be ignored.

Some existing generation units managed by Duke Energy in North Carolina have estimated retirement dates available at [46, 47] (123 units – 24.5 GW – 63% of the N.C. existing capacity). Because of those generation units, modifications to the available capacity were made at each vintage to ensure proper capacity retirement of each technology type. However, for generators without estimated retirement dates from Duke Energy [46, 47], the lifetimes reported in Tables 2.4 and 2.5 were assumed.

It is important to mention that due to limitations on data availability and model approximations, an existing generator reported at the EIA-860M [28] and not available at [46, 47] may be retired prior to the first year of simulation (year 2023), as we consider an average retirement date for all generators not referenced on [46, 47]. In this case, this capacity is eliminated from the pool of existing capacity; these conditions account for less than 0.39GW (less than 1% of the N.C. existing capacity).

Figure 2.2 shows the retirement dates and capacity for existing technologies retired after 2023, and Figure 2.3 shows the retirement dates and capacity for existing technologies retired before or in 2023 (a modeling effect of the values in Tables 2.4 and 2.5).

A graph with numbers and letters

Description automatically generated with medium confidence

\*A technology retired at year X does not contribute to the generation at year X.

**Figure 2.2:** Retirement Year and Capacity for Existing Technologies Retired After 2023.

A graph of different colored bars

Description automatically generated

\*A technology retired at year X does not contribute to the generation at year X.

**Figure 2.3:** Retirement Year and Capacity for “Existing Technologies Retired Before or at 2023”. This Happens Because of the Average Lifetime Approximations Considered and Limitations on Data Availability. This Corresponds To Less Than 1% of the Existing Capacity.

Finally, Figure 2.4 summarizes the total installed capacity for existing technologies considered by the capacity expansion model simulation from 2023 to 2055.

A graph of different colored lines

Description automatically generated

**Figure 2.4:** Summary of Total Capacity for Existing Technologies Considering The Capacity Expansion Model. Capacity Decreases as Existing Technologies Retire.

* 1. **Costs**

In this work, we assume that new capacity can only be added using the technologies described in Table 2.7, which also contains the investment costs in millions of dollars per new G.W. installed at each future period in the capacity expansion model. Table 2.7 also contains the discount rate (weighted average cost of capital) for each technology investment.

**Table 2.7:** Investment Cost For New Technologies and Discount Rates

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology Code** | **Investment Cost at Different Tech Vintages [M$/GW]** | | | | | | | **Discount**  **Rate** | **Reference** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| BATT\_2H\_NEW | 809 | 762 | 682 | 682 | 682 | 682 | 682 | 0.065 | [45] |
| BATT\_4H\_NEW | 1394 | 1312 | 1174 | 1174 | 1174 | 1174 | 1174 | 0.065 | [45] |
| BATT\_6H\_NEW | 1978 | 1862 | 1666 | 1666 | 1666 | 1666 | 1666 | 0.065 | [45] |
| BATT\_8H\_NEW | 2563 | 2413 | 2158 | 2158 | 2158 | 2158 | 2158 | 0.065 | [45] |
| BIOMASS\_CC90\_NEW\* | 5529 | 5495 | 5410 | 5333 | 5255 | 5178 | 5100 | 0.058 | [33, 45] |
| BIOMASS\_NEW | 4332 | 4276 | 4186 | 4046 | 3906 | 3766 | 3626 | 0.058 | [45] |
| CO2\_STORAGE | Assuming no Investment Costs and Only Variable Costs as in The NREL ReEDS Model [45] | | | | | | | | |
| COAL\_95CC\_NEW | 4750 | 4677 | 4495 | 4313 | 4131 | 3949 | 3766 | 0.065 | [45] |
| COAL\_99CC\_NEW | 4860 | 4786 | 4599 | 4414 | 4227 | 4040 | 3853 | 0.065 | [45] |
| COAL\_NEW | 3047 | 3027 | 2962 | 2861 | 2761 | 2664 | 2567 | 0.065 | [45] |
| DISTRIBUTION | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.050 |  |
| NG\_F-FRAME\_CC\_95CC\_NEW | 2117 | 2066 | 1974 | 1892 | 1812 | 1732 | 1658 | 0.065 | [45] |
| NG\_F-FRAME\_CC\_97CC\_NEW | 2150 | 2099 | 2004 | 1922 | 1841 | 1760 | 1683 | 0.065 | [45] |
| NG\_F-FRAME\_CC\_NEW | 1026 | 1010 | 989 | 967 | 946 | 925 | 905 | 0.065 | [45] |
| NG\_F-FRAME\_CT\_NEW | 900 | 872 | 838 | 815 | 793 | 772 | 750 | 0.065 | [45] |
| NG\_H-FRAME\_CC\_95CC\_NEW | 1997 | 1948 | 1862 | 1785 | 1709 | 1635 | 1564 | 0.065 | [45] |
| NG\_H-FRAME\_CC\_97CC\_NEW | 2027 | 1978 | 1889 | 1811 | 1736 | 1659 | 1587 | 0.065 | [45] |
| NG\_H-FRAME\_CC\_NEW | 981 | 958 | 929 | 909 | 889 | 869 | 854 | 0.065 | [45] |
| NUCLEAR-AP1000\_NEW | 7302 | 7040 | 6966 | 6731 | 6496 | 6261 | 6026 | 0.058 | [45] |
| NUCLEAR-SMR\_NEW | 7839 | 7739 | 7661 | 7405 | 7150 | 6894 | 6639 | 0.058 | [45] |
| PV-COMMERCIAL\_NEW | 1574 | 1549 | 1494 | 1352 | 1210 | 1069 | 927 | 0.056 | [45] |
| PV-RESIDENTIAL\_NEW | 2569 | 2488 | 2285 | 1968 | 1651 | 1334 | 1016 | 0.057 | [45] |
| PV-UTILITY\_NEW | 1161 | 1157 | 1150 | 1051 | 952 | 853 | 754 | 0.053 | [45] |
| TRANSMISSION\_INTERREGIONAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.050 |  |
| TRANSMISSION\_REGIONAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.050 |  |
| WAT\_HY\_NEW | 2574 | 2574 | 2590 | 2590 | 2590 | 2590 | 2590 | 0.054 | [45]-Class 1 |
| WAT\_PS\_NEW | 1999 | 1999 | 2011 | 2011 | 2011 | 2011 | 2011 | 0.054 | [45]-Class 1 |
| WIND-LAND-C8\_NEW | 1323 | 1231 | 1006 | 981 | 956 | 931 | 906 | 0.071 | [45]-Class 8 |
| WIND-OFFSHORE-C6\_NEW | 3855 | 3726 | 3570 | 3450 | 3362 | 3294 | 3238 | 0.066 | [45]-Class 6 |

\*Costs from [33], discount rate from [45]

Table 2.8 contains the fixed and variable costs for the existing generation technologies represented in the capacity expansion model.

**Table 2.8:** Fixed and Variable Costs for Existing Generation

|  |  |  |  |
| --- | --- | --- | --- |
| **Technology Code** | **Fixed Cost [M$/GWyr]**  **Same For all Vintages and Periods** | **Variable Cost [$/MWh]**  **Same For all Vintages and Periods** | **Reference\*** |
| AB\_ST\_EXISTING | 151 | 5.8 | [45]-Biopower (Conservative-2020) |
| BIT\_ST\_EXISTING | 141 | 13.86 | [45]-Coal IGCC (Conservative-2020) |
| BLQ\_ST\_EXISTING | 151 | 5.8 | [45]-Biopower (Conservative-2020) |
| DFO\_CC\_EXISTING | 28 | 1.78 | [45]-Same as NG F-Frame CC \*\* (Conservative-2020) |
| DFO\_GT\_EXISTING | 21 | 5.1 | [45]-Same as NG F-Frame CT \*\* (Conservative-2020) |
| DFO\_IC\_EXISTING | 21 | 5.1 | [45]-Same as NG F-Frame CT \*\* (Conservative-2020) |
| LFG\_GT\_EXISTING | 151 | 5.8 | [45]-Biopower (Conservative-2020) |
| LFG\_IC\_EXISTING | 151 | 5.8 | [45]-Biopower (Conservative-2020) |
| MWH\_BA1H\_EXISTING | 31 | 0 | [45]-Commercial Storage (Conservative-2020) |
| MWH\_BA2H\_EXISTING | 25 | 0 | [45]-Utility Storage (Conservative-2020) |
| NG\_CC\_EXISTING | 28 | 1.78 | [45]-NG F-Frame CC (Conservative-2020) |
| NG\_GT\_EXISTING | 21 | 5.1 | [45]-NG F-Frame CT (Conservative-2020) |
| NG\_ST\_EXISTING | 21 | 5.1 | [45]-NG F-Frame CT (Conservative-2020) |
| NUC\_ST\_EXISTING | 146 | 2.84 | [45]-Nuclear AP1000 (Conservative-2020) |
| OBG\_IC\_EXISTING | 151 | 5.8 | [45]-Biopower (Conservative-2020) |
| SUN\_PV\_EXISTING | 23 | 0 | [45]-Solar Utility (Conservative-2020) |
| WAT\_HY\_EXISTING | 64 | 0 | [45]-Hydropower Class 1 (Conservative-2020) |
| WAT\_PS\_EXISTING | 18 | 0.513 | [45]-Pumped Hydropower Class 1 (Conservative-2020) |
| WDS\_ST\_EXISTING | 151 | 5.8 | [45]-Biopower (Conservative-2020) |
| WH\_ST\_EXISTING | 21 | 5.1 | [45]-Same as NG F-Frame CT (Conservative-2020) |
| WND\_WT\_EXISTING | 43 | 0 | [45]-Wind Class C8 (Conservative-2020) |

\*Reference and comment on the technology (in the reference) considered equivalent to the technology code

\*\*Gas turbines can typically run either on natural gas or refined liquid fuels

Tables 2.9 and 2.10 contain the fixed costs for the new-generation and non-generation technologies represented in the capacity expansion model. Technologies with zero fixed costs are not represented.

**Table 2.9:** Fixed Costs for New Generation

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology Code** | **Fixed Cost at Different Tech Vintages [M$/GWyear]**  **(Only Varies With the Vintage)** | | | | | | | **Reference** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| BATT\_2H\_NEW | 20 | 19 | 17 | 17 | 17 | 17 | 17 | [45] |
| BATT\_4H\_NEW | 35 | 33 | 29 | 29 | 29 | 29 | 29 | [45] |
| BATT\_6H\_NEW | 49 | 47 | 42 | 42 | 42 | 42 | 42 | [45] |
| BATT\_8H\_NEW | 64 | 60 | 54 | 54 | 54 | 54 | 54 | [45] |
| BIOMASS\_CC90\_NEW | 162 | 162 | 162 | 162 | 162 | 162 | 162 | [33] |
| BIOMASS\_NEW | 151 | 151 | 151 | 151 | 151 | 151 | 151 | [45] |
| COAL\_95CC\_NEW | 115 | 115 | 115 | 115 | 115 | 115 | 115 | [45] |
| COAL\_99CC\_NEW | 117 | 117 | 117 | 117 | 117 | 117 | 117 | [45] |
| COAL\_NEW | 74 | 74 | 74 | 74 | 74 | 74 | 74 | [45] |
| NG\_F-FRAME\_CC\_95CC\_NEW | 58 | 58 | 58 | 58 | 58 | 58 | 58 | [45] |
| NG\_F-FRAME\_CC\_97CC\_NEW | 59 | 59 | 59 | 59 | 59 | 59 | 59 | [45] |
| NG\_F-FRAME\_CC\_NEW | 28 | 28 | 28 | 28 | 28 | 28 | 28 | [45] |
| NG\_F-FRAME\_CT\_NEW | 21 | 21 | 21 | 21 | 21 | 21 | 21 | [45] |
| NG\_H-FRAME\_CC\_95CC\_NEW | 53 | 53 | 53 | 53 | 53 | 53 | 53 | [45] |
| NG\_H-FRAME\_CC\_97CC\_NEW | 54 | 54 | 54 | 54 | 54 | 54 | 54 | [45] |
| NG\_H-FRAME\_CC\_NEW | 27 | 27 | 27 | 27 | 27 | 27 | 27 | [45] |
| NUCLEAR-AP1000\_NEW | 146 | 146 | 146 | 146 | 146 | 146 | 146 | [45] |
| NUCLEAR-SMR\_NEW | 114 | 114 | 114 | 114 | 114 | 114 | 114 | [45] |
| PV-COMMERCIAL\_NEW | 18 | 17 | 17 | 16 | 14 | 13 | 12 | [45] |
| PV-RESIDENTIAL\_NEW | 28 | 27 | 25 | 22 | 19 | 16 | 13 | [45] |
| PV-UTILITY\_NEW | 20 | 20 | 20 | 19 | 18 | 16 | 15 | [45] |
| WAT\_HY\_NEW | 64 | 64 | 64 | 64 | 64 | 64 | 64 | [45]-Class 1 |
| WAT\_PS\_NEW | 18 | 18 | 18 | 18 | 18 | 18 | 18 | [45]-Class 1 |
| WIND-LAND-C8\_NEW | 43 | 43 | 43 | 43 | 42 | 42 | 41 | [45]-Class 8 |
| WIND-OFFSHORE-C6\_NEW | 115 | 112 | 106 | 102 | 99 | 97 | 95 | [45]-Class 6 |

**Table 2.10:** Fixed Costs For Non-Generation Technologies

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology Code** | **Fixed Cost Tech at Different Tech Vintages [M$/GWyear]** | | | | | | | **Reference** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| DISTRIBUTION | 0 | 0 | 0 | 0 | 0 | 0 | 0 |  |
| TRANSMISSION\_INTERREGIONAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |  |
| TRANSMISSION\_REGIONAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |  |

Tables 2.11 and 2.12 contain the variable costs of the new-generation and non-generation technologies represented in the capacity expansion model. Technologies with zero variable cost are not shown for simplicity.

**Table 2.11:** Variable Costs for New Generation

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology Code** | **Variable Cost at Different Tech Vintages [$/MWh]**  **(Only Varies With the Vintage)** | | | | | | | **Reference** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| BIOMASS\_CC90\_NEW | 16.60 | 16.60 | 16.60 | 16.60 | 16.60 | 16.60 | 16.60 | [33] |
| BIOMASS\_NEW | 5.80 | 5.80 | 5.80 | 5.80 | 5.80 | 5.80 | 5.80 | [45] |
| COAL\_95CC\_NEW | 14.03 | 14.03 | 14.03 | 14.03 | 14.03 | 14.03 | 14.03 | [45] |
| COAL\_99CC\_NEW | 14.37 | 14.37 | 14.37 | 14.37 | 14.37 | 14.37 | 14.37 | [45] |
| COAL\_NEW | 7.96 | 7.96 | 7.96 | 7.96 | 7.96 | 7.96 | 7.96 | [45] |
| NG\_F-FRAME\_CC\_95CC\_NEW | 4.30 | 4.30 | 4.30 | 4.30 | 4.30 | 4.30 | 4.30 | [45] |
| NG\_F-FRAME\_CC\_97CC\_NEW | 4.30 | 4.30 | 4.30 | 4.30 | 4.30 | 4.30 | 4.30 | [45] |
| NG\_F-FRAME\_CC\_NEW | 1.78 | 1.78 | 1.78 | 1.78 | 1.78 | 1.78 | 1.78 | [45] |
| NG\_F-FRAME\_CT\_NEW | 5.10 | 5.10 | 5.10 | 5.10 | 5.10 | 5.10 | 5.10 | [45] |
| NG\_H-FRAME\_CC\_95CC\_NEW | 4.09 | 4.09 | 4.09 | 4.09 | 4.09 | 4.09 | 4.09 | [45] |
| NG\_H-FRAME\_CC\_97CC\_NEW | 4.09 | 4.09 | 4.09 | 4.09 | 4.09 | 4.09 | 4.09 | [45] |
| NG\_H-FRAME\_CC\_NEW | 1.76 | 1.76 | 1.76 | 1.76 | 1.76 | 1.76 | 1.76 | [45] |
| NUCLEAR-AP1000\_NEW | 2.84 | 2.84 | 2.84 | 2.84 | 2.84 | 2.84 | 2.84 | [45] |
| NUCLEAR-SMR\_NEW | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | [45] |
| WAT\_PS\_NEW | 0.513 | 0.513 | 0.513 | 0.513 | 0.513 | 0.513 | 0.513 | [45]-Class 1 |

**Table 2.12:** Variable Costs For Non-Generating Technologies

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology Code** | **Variable Cost at Different Periods**  **(Does not Vary With the Tech Vintage**  **But Vary With The Period)** | | | | | | | **Reference** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| CO2\_STORAGE [$/Metric Ton CO2] | 12.87 | 12.87 | 12.87 | 12.87 | 12.87 | 12.87 | 12.87 | [48]\* |
| DISTRIBUTION | 0 | 0 | 0 | 0 | 0 | 0 | 0 |  |
| FT\_BIOMASS [$/MMBTU] | 5 | 5 | 5 | 5 | 5 | 5 | 5 | [45] |
| FT\_COAL [$/MMBTU] | 5.84 | 4.10 | 3.21 | 3.71 | 4.01 | 3.86 | 3.75 | [29]- AEO23 Reference Case |
| FT\_NG [$/MMBTU] | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | [29]- AEO23 Reference Case |
| FT\_NUCLEAR [$/MMBTU] | 14.66 | 13.43 | 13.23 | 13.72 | 14.13 | 14.42 | 14.83 | [29]- AEO23 Reference Case |
| FT\_PETROLEUM [$/MMBTU] | 2.25 | 2.20 | 2.04 | 2.06 | 2.02 | 2.02 | 2.01 | [29]- AEO23 Reference Case |
| TRANSMISSION\_INTERREGIONAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |  |
| TRANSMISSION\_REGIONAL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |  |

\*$11/tonne (2011$)- Converted to 2020 using 1.17 rate

For all tables shown in this section, when reference [45] is used, cost values refer to the conservative cost assumption from ATB 22 if otherwise not specified.

* 1. **Efficiency**

Table 2.13 shows the fuel-to-electricity conversion rates for existing generation technologies, represented in the capacity expansion model.

**Table 2.13:** Fuel to Electricity Conversion Rates For Existing Generation Technologies

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Technology Code** | **Units** | **Fuel** | **Efficiency-Same for All Periods and Tech Vintages** | **Reference** |
| AB\_ST\_EXISTING | [MMBtu/MWh] | Biomass | 20.46 | [49] |
| BIT\_ST\_EXISTING | [MMBtu/MWh] | Coal | 10.38 | [49] |
| BLQ\_ST\_EXISTING | [MMBtu/MWh] | Biomass | 5.31 | [49] |
| DFO\_CC\_EXISTING | [MMBtu/MWh] | Petroleum | 10.17 | [49] |
| DFO\_GT\_EXISTING | [MMBtu/MWh] | Petroleum | 11.61 | [49] |
| DFO\_IC\_EXISTING | [MMBtu/MWh] | Petroleum | 11.82 | [49] |
| LFG\_GT\_EXISTING | [MMBtu/MWh] | Landfill Gas | 16.22 | [49] |
| LFG\_IC\_EXISTING | [MMBtu/MWh] | Landfill Gas | 10.59 | [49] |
| MWH\_BA1H\_EXISTING | [MWh/MWh] | Electricity | 0.85 | [33] |
| MWH\_BA2H\_EXISTING | [MWh/MWh] | Electricity | 0.85 | [33] |
| NG\_CC\_EXISTING | [MMBtu/MWh] | Natural Gas | 7.97 | [49] |
| NG\_GT\_EXISTING | [MMBtu/MWh] | Natural Gas | 11.62 | [49] |
| NG\_ST\_EXISTING | [MMBtu/MWh] | Natural Gas | 9.92 | [49] |
| NUC\_ST\_EXISTING | [MMBtu/MWh] | Uranium | 10.43 | [49] |
| OBG\_IC\_EXISTING | [MMBtu/MWh] | Biomass | 10.24 | [49] |
| WAT\_PS\_EXISTING | [MWh/MWh] | Electricity | 0.80 | [33] |
| WDS\_ST\_EXISTING | [MMBtu/MWh] | Biomass | 11.04 | [49] |

Table 2.14 shows the fuel-to-electricity conversion rates for new generation technologies, represented in the capacity expansion model.

**Table 2.14:** Fuel to Electricity Conversion Rates For New Generation Technologies

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology Code** | **Units** | **Fuel** | **Efficiency at Different Tech Vintages**  **(Only Varies With the Vintage)** | | | | | | | **Reference** |
| **2023** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| BATT\_2H\_NEW | [MWh/MWh] | Electricity | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | [33] |
| BATT\_4H\_NEW | [MWh/MWh] | Electricity | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | [33] |
| BATT\_6H\_NEW | [MWh/MWh] | Electricity | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | [33] |
| BATT\_8H\_NEW | [MWh/MWh] | Electricity | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | [33] |
| BIOMASS\_CC90\_NEW | [MMBtu/MWh] | Biomass | 8.10 | 8.04 | 7.91 | 7.78 | 7.66 | 7.54 | 7.41 | [49, 33]\* |
| BIOMASS\_NEW | [MMBtu/MWh] | Biomass | 7.21 | 7.21 | 7.21 | 7.21 | 7.21 | 7.21 | 7.21 | [49]\*\* |
| COAL\_95CC\_NEW | [MMBtu/MWh] | Coal | 10.94 | 10.94 | 10.94 | 10.94 | 10.94 | 10.94 | 10.94 | [45] |
| COAL\_99CC\_NEW | [MMBtu/MWh] | Coal | 11.12 | 11.12 | 11.12 | 11.12 | 11.12 | 11.12 | 11.12 | [45] |
| COAL\_NEW | [MMBtu/MWh] | Coal | 8.49 | 8.49 | 8.49 | 8.49 | 8.49 | 8.49 | 8.49 | [45] |
| NG\_F-FRAME\_CC\_95CC\_NEW | [MMBtu/MWh] | Natural Gas | 7.22 | 7.22 | 7.22 | 7.22 | 7.22 | 7.22 | 7.22 | [45] |
| NG\_F-FRAME\_CC\_97CC\_NEW | [MMBtu/MWh] | Natural Gas | 7.26 | 7.26 | 7.26 | 7.26 | 7.26 | 7.26 | 7.26 | [45] |
| NG\_F-FRAME\_CC\_NEW | [MMBtu/MWh] | Natural Gas | 6.36 | 6.36 | 6.36 | 6.36 | 6.36 | 6.36 | 6.36 | [45] |
| NG\_F-FRAME\_CT\_NEW | [MMBtu/MWh] | Natural Gas | 9.72 | 9.72 | 9.72 | 9.72 | 9.72 | 9.72 | 9.72 | [45] |
| NG\_H-FRAME\_CC\_95CC\_NEW | [MMBtu/MWh] | Natural Gas | 7.01 | 7.01 | 7.01 | 7.01 | 7.01 | 7.01 | 7.01 | [45] |
| NG\_H-FRAME\_CC\_97CC\_NEW | [MMBtu/MWh] | Natural Gas | 7.05 | 7.05 | 7.05 | 7.05 | 7.05 | 7.05 | 7.05 | [45] |
| NG\_H-FRAME\_CC\_NEW | [MMBtu/MWh] | Natural Gas | 6.20 | 6.20 | 6.20 | 6.20 | 6.20 | 6.20 | 6.20 | [45] |
| NUCLEAR-AP1000\_NEW | [MMBtu/MWh] | Uranium | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | [45] |
| NUCLEAR-SMR\_NEW | [MMBtu/MWh] | Uranium | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | [45] |
| WAT\_PS\_NEW | [MWh/MWh] | Electricity | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | [33] |

\*Average values from all biomass technologies reported on EIA-923 [49] times increase in heat rate for BECC tech in ReEDS [33]

\*\*Average values from all biomass technologies reported on EIA-923 [49]. Used as a way to account for the use of different biofuels in NC

Table 2.15 shows the efficiencies for non-generating technologies.

**Table 2.15:** Efficiency For Non-Generating Technologies

|  |  |  |
| --- | --- | --- |
| **Technology Code** | **Efficiency** | **Reference/Rational** |
| DISTRIBUTION | 96.96 | From [42], NC had 4.96% T&D losses from 2021-2019. Using [50] as an approximate reference, assume 40% of these losses are due to transmission and 60% due to distribution. |
| TRANSMISSION\_REGIONAL | 98.02 |

* 1. **Emission Activity and Limits**

Tables 2.16 and 2.17 show the emissions per MMBtu of fuel used by different technologies considered in our simulation.

**Table 2.16:** Technology Emission per MMBtu of Fuel Used (Existing Tech)

|  |  |  |  |
| --- | --- | --- | --- |
| **Technology Code** | **Fuel** | **Lbs CO2 / MMBtu** | **Reference** |
| AB\_ST\_EXISTING | Biomass | 0 | [45] |
| BIT\_ST\_EXISTING | Coal | 214.13 | Emissions from [42], fuel consumption from [49] |
| BLQ\_ST\_EXISTING | Biomass | 0 | [45] |
| DFO\_CC\_EXISTING | Petroleum | 229.79 | Emissions from [42], fuel consumption from [49] |
| DFO\_GT\_EXISTING | Petroleum | 229.79 | Emissions from [42], fuel consumption from [49] |
| DFO\_IC\_EXISTING | Petroleum | 229.79 | Emissions from [42], fuel consumption from [49] |
| LFG\_GT\_EXISTING | Landfill Gas | 0 | [45] |
| LFG\_IC\_EXISTING | Landfill Gas | 0 | [45] |
| NG\_CC\_EXISTING | Natural Gas | 119.42 | Emissions from [42], fuel consumption from [49] |
| NG\_GT\_EXISTING | Natural Gas | 119.42 | Emissions from [42], fuel consumption from [49] |
| NG\_ST\_EXISTING | Natural Gas | 119.42 | Emissions from [42], fuel consumption from [49] |
| OBG\_IC\_EXISTING | Biomass | 0 | [45] |
| WDS\_ST\_EXISTING | Biomass | 0 | [45] |

**Table 2.16:** Technology Emission per MMBtu of Fuel Used (New Tech)

|  |  |  |  |
| --- | --- | --- | --- |
| **Technology Code** | **Fuel** | **Lbs CO2 / MMBtu** | **Reference** |
| BIOMASS\_CC90\_NEW | Biomass | -190.37 | [51, 28]\* |
| BIOMASS\_NEW | Biomass | 0 | [45] |
| COAL\_95CC\_NEW | Coal | 10.12 | [45] |
| COAL\_99CC\_NEW | Coal | 2.02 | [45] |
| COAL\_NEW | Coal | 202.32 | [45] |
| NG\_F-FRAME\_CC\_95CC\_NEW | Natural Gas | 5.93 | [45] |
| NG\_F-FRAME\_CC\_97CC\_NEW | Natural Gas | 3.558 | [45] |
| NG\_F-FRAME\_CC\_NEW | Natural Gas | 118.6 | [45] |
| NG\_F-FRAME\_CT\_NEW | Natural Gas | 118.6 | [45] |
| NG\_H-FRAME\_CC\_95CC\_NEW | Natural Gas | 5.93 | [45] |
| NG\_H-FRAME\_CC\_97CC\_NEW | Natural Gas | 3.558 | [45] |
| NG\_H-FRAME\_CC\_NEW | Natural Gas | 118.62 | [45] |

\*CO2 data in lb/MMBtu for various biomass resources was collected from reference [51]. A weighted average was then calculated using the total MMBtu consumed of fuel by each technology in North Carolina [49] (2021) to determine a comparable emission value, which was then adjusted for 90% carbon capture. (EIA Fuel Code [lbs CO2/MMBtu] [51]: LFG=130, OBG=127, BLQ=222, ABWDS=207).

Regarding the limits on CO2 emissions, according to the N.C. - House Bill 951 [52], the electric power sector should plan to achieve 70% CO2 reduction from 2005 levels by 2030 and reach carbon neutrality by 2050. In 2005, the N.C. electric power sector was estimated to emit 80.15 million metric tons of CO2 [43]. Therefore, by 2030, this work considers a maximum CO2 emission of 24.05 million metric tons, with zero net emissions by 2050.

* 1. **Capacity Factors and Max/Min Capacity/Activity**
     1. **Solar**

Data for global horizontal irradiance was downloaded from the NREL SAM model [53] from 1998 to 2020 for the load centroids of the three regions investigated in this work. Figure 1 shows the distribution of the total irradiance for each region by time of day and season. As it is possible to see, there are very small differences between each region's resources. As such, no distinction was made regarding the C.F. of solar in different regions.

For utility P.V., from EIA 860 report [54] we can estimate that 90.6% of the total utility solar installed in NC form 2008-2021 is fixed til, 8.3% is 1-axis tracking and 1.1% is 2-axis tracking. From 2020 to 2021 79% of new solar installations were fixed tilt, 15% were 1-axis and 6% were 2-axis tracking. As a simplification, we assumed that all existing utility solar installations in N.C. follow a C.F. distribution composed of 90% fixed tilt and 10% 1-axis tracking, and that all future utility P.V. installations are composed of 80% fixed tilt and 20% 1-axis tracking. For residential and commercial solar, all P.V. generation is assumed to be fixed tilt. Figure 2 shows the C.F. profiles for fixed tilt and one-axis tracking solar P.V.s computed using the NREL PVWATT v.6 model [55] for the N.C. region.

|  |  |
| --- | --- |
|  |  |
| **Figure 1:** Percentage of total irradiance for solar technologies in different regions of NC | **Figure 2:** C.F. for 1-Axis Tracking and Fixed-Tilt Solar Energy Generation. Adjusted for an Annual C.F. of 0.215 |

Considering the 2021 EIA NC Summary Statistics report [42], the average annual C.F. of existing utility solar can be estimated at 0.215 in N.C. Using the ATB 2022 conversions from utility to residential and commercial solar [45] (2020 conservative scenario), a 0.12 capacity factor was estimated for existing residential/commercial solar. The final capacity factors for existing solar technologies are shown in Figure 3.

As solar energy technology evolves, it is expected improvements in cost as well as in capacity factors. For future solar deployments, the annual C.F. estimates from the NREL ATB- 2022 [45] for technology class C6 (GHI 4.5-4.75 kWh/m2/day) were used to adjust the curves shown in Figure 3. Figure 4 shows the annual C.F.s considered in this work for different solar technologies.

|  |  |
| --- | --- |
|  |  |
| **Figure 3:** C.F. for Existing Utility and Residential Solar in NC | **Figure 4:** Average Annual C.F. for Solar Technologies By Deployment Year. C.F. For Existing Tech Shown For Comparison |

Regarding maximum capacity limits for solar, according to NREL [56], N.C. has the potential for 2953 TWh of utility P.V. generation, 17992 GWh of residential solar, and 23572 GWh of commercial solar. Due to the high availability of solar resources compared to the state electricity demand, this work found it unnecessary to enforce maximum limits of solar deployment. With respect to limits for minimum activity, the analysis made in Section 2.3 (Energy Demand, See tables 2 and 3) was used to estimate residential and commercial solar energy generation in N.C. throughout the optimization periods considered in this work. These values are shown in Table 1 and were enforced as minimum activity in the optimization model.

Also, due to the complexity of estimating the size of distributed solar energy at each year from before 2023, all existing distributed solar was approximate as being deployed in 2017, which corresponds to the average year of deployment for the current installed utility solar (weighted by capacity) in N.C. according to the 2022 EIA 860 report [54].

**Table 1:** Minimum Activity Enforced for Distributed Solar Energy Generation in North Carolina

|  |  |  |
| --- | --- | --- |
| **Year** | **Generation from Solar Residential**  **[GWh]** | **Generation from Solar Commercial**  **[GWh]** |
| 2022- Existing Solar\* | 334 | 121 |
| 2023 | 406 | 137 |
| 2025 | 528 | 173 |
| 2030 | 835 | 264 |
| 2035 | 1,787 | 390 |
| 2040 | 2,539 | 488 |
| 2045 | 3,306 | 537 |
| 2050 | 4,239 | 570 |

\* Estimated as done in Table 3 (Demand Section) Using 2022 data for DEC+DEP (Table 2 -Demand Section). This Value is Considered as Existing Distributed Solar.

Finally, since this work considered the segmentation of N.C. in multiple regions (R1, R2, and R3), as explained in the previous sections, the minimum activity limits shown in Table 1 were distributed based on the percentage of the total population at each region. Using the 2020 census [31], the ratios considered were 7.02%, 12.98%, and 80.00% for regions R1, R2, and R3, respectively.

* + 1. **Wind**

A resource characterization for wind energy technologies is provided by NREL in [57], with available capacity and annual C.F. for viable site locations based on 2030 ATB moderate designs [45]. This reference is used to compute the maximum available capacity and C.F.s for each of the N.C. regions modeled in this work. Site locations with C.F. below 0.25 were eliminated from the analysis of land-based wind as these are less likely to be explored and correspond to less than 17% of the total land-based wind power available in NC [57]. For offshore technologies, according to the ATB 22 [45], fixed bottom wind turbines (Class C1 to C7) are more likely to be explored in the near future. As such, the N.C. offshore wind site locations mapped by NREL [57] were filtered to account for sites with a maximum of 40m depth and distancing a maximum of 100km from shore.

Table 1 shows the resultant maximum available capacity and average annual C.F. for land-based and offshore technologies. The column “2030 - Annual C.F.” refers to the C.F. estimated directly from reference [57], which accounts for 2030 wind technologies, and the column “2020 - Annual C.F.” corresponds to the conversion of the 2030 C.F.s for 2020 equivalent technology using ATB 22 [45] estimates. Table 1 also shows the C.F. for existing wind energy technology, computed as the average values reported in [42] from 2021 to 2018.

**Table 1:** Maximum Available Capacity and C.F. For Wind Technology

|  |  |  |  |
| --- | --- | --- | --- |
| **Technology** | **Max Capacity**  **(G.W.)** | **Annual C.F. - 2030 Tech**  **(NREL 2030 Moderate Technology)** | **Annual C.F. – 2020 Tech**  **(ATB -2022 Conversion-**  **Conservative Case)** |
| New Offshore Wind\* | 15.26 | 0.427 | 0.378 |
| New Land-Based Wind (R1)\*\* | 0.85 | 0.410 | 0.382 |
| New Land-Based Wind (R2)\*\* | 4.07 | 0.402 | 0.374 |
| New Land-Based Wind (R3)\*\* | 11.00 | 0.330 | 0.307 |
|  |  |  |  |
| **Technology** | **Existing capacity (G.W.)** | **C.F. (N.C. Average Statistics 2021-2018)** [42] | |
| Existing Land-Based Wind\*\*\* | 0.21 | 0.290 | |

\* Based on [57], limited access case. \*\*Based on [57], reference access case.

To find the C.F. variation for wind generation during different hours of the day and seasons, the operation of hypothetical wind turbines was simulated across the region of study, and the average C.F. profile from these operations at each region was used for wind technologies. Two to three sample wind site locations were considered for each N.C. region, as in Figure 3, with wind speed data coming from the NREL SAM model [53] from 2007 to 2013, and the turbine design and parameters chosen based on NREL ATB- 2022 [45] conservative designs. For land-based wind, the turbine was rated at 4MW with 110m hub height, and for offshore wind, the turbine was rated at 12MW with 136m hub height; the power curves for these designs were obtained from the NREL SAM model [53].

|  |
| --- |
|  |
| **Figure 3:** Sample Locations Used for Determining the C.F. Profile of Wind on N.C. Showing Sites With Capacity Above 20MW |

Finally, as done for solar energy generation, the C.F. profile at each region was adjusted to match the annual C.F. values reported in Table 1 for the year 2020, corrected by the technology vintage based on C.F. rates of improvement from NREL ATB- 2022 [45] (conservative case). Figure 4 shows the C.F.s profile for the wind technologies, and Figure 5 shows the average annual C.F. by deployment year.

|  |  |
| --- | --- |
|  |  |
| **Figure 4:** C.F. Profile For Wind Technology From Simulation of Individual Turbines (2007-2013) | **Figure 5:** Average Annual C.F. for Wind Technologies By Deployment Year. C.F. For Existing Tech is Also Shown For Comparison |

* + 1. **Hydropower**

For hydropower generation, the C.F. was assumed to vary only with the season and not with the time of the day, which is a common practice in many capacity expansion studies. The C.F. values used in this work for hydro technologies are shown in Table 1 and were computed by averaging the monthly C.F. values reported from 2017 to 2021 in the North Carolina electricity summary statistics [42, 58, 59, 60, 61].

In terms of maximum and minimum capacity for hydropower and pumped storage (shown in Table 1), this work assumes that the current installed capacity reported in the EIA-860 [28] is the maximum capacity available for each technology type. From the perspective of pumped storage, although Duke Energy has plans to add new capacity in South Carolina by 2035 [27] the same is not true for North Carolina, and from the perspective of new hydropower plants, existing environmental regulations and costs are likely to difficult increases in hydropower capacity above the current levels.

**Table 1:** Capacity Factor and Maximum Available Capacity For Hydropower

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Technology** | **Capacity Factor** | | | | **Maximum Capacity Available [M.W.]** |
| **S1-Winter** | **S2-Spring** | **S3-Summer** | **S4-Autumn** |
| WAT\_HY (EXISTING/NEW) | 0.389 | 0.385 | 0.302 | 0.316 | 2057.6 |
| WAT\_PS (EXISTING/NEW) | -\*\* | -\*\* | -\*\* | -\*\* | 95.0 |

\*Different from solar and wind, this technology does not have adjustments in C.F. due to tech vintage; \*\*No C.F. assumed for pumped hydro.

* + 1. **Biomass**

For biomass technologies, C.F. is used to limit the maximum average generation of technology throughout the years of simulation due to planned/non-planned outages. This value is determined using the Equivalent Availability Factor (EAF) reported by NERC [62] from 2017-2021 for coal turbines.

A maximum value for the amount of biomass available for use by the electric power sector in N.C. is also estimated using data from the 2016 Billion-Ton Report [63]. From reference [63], we assumed a maximum biomass price of 60$ per dry ton and that only biomass from forestry and waste would be available to the power sector (agricultural biomass is ignored, assuming it would be used to create biofuels). Dry ton units were converted to MMBtu using rates of 13 MMBtu/ton for forestry and 8MMBtu/ton for waste [63]. Landfill gas is also considered as part of the biomass technologies, and the total Btus available are assumed to not vary substantially from current consumption levels provided at the EIA 923 reports [64]

Table 1 summarizes the information mentioned above.

**Table 1:** Capacity Factor and Maximum Available Resource for Biomass Technology

|  |  |
| --- | --- |
| **Technology** | **C.F. (EAF)** |
| All Biomass Technologies | 0.786 |
|  |  |
| **Biomass Resource** | **Max Resource Available [Trillion Btu ]** |
| Forestry\* [63] | 64.28\* |
| Waste\* [63] | 48.16\* |
| Landfill Gas [64] | 5.16 |
| Total Biomass Available | 117.6 |

\*Average of the estimates provided in [63] from 2015-2040

* + 1. **Other Technologies**

In terms of coal, petrol, natural gas, and nuclear technologies, no max/min capacity limits were enforced; however, as done for biomass, the correspondent Equivalent Availability Factors (EAF) reported by NERC [62] from 2017-2021 were used as a way to limit the maximum average generation of each technology due to planned/non-planned outages.

**Table 1:** Capacity Factor and Maximum for Coal, Petrol, Natural Gas, and Nuclear Technologies

|  |  |
| --- | --- |
| **Technology Type** | **C.F. (EAF)** |
| Coal | 0.786 |
| Petrol | 0.781 |
| Natural Gas | 0.772 |
| Nuclear | 0.91 |

* 1. **Planning Reserve Margin and Capacity Credit**

Planning reserve requirements refer to the share of peak load that must be available to meet contingencies. In North Carolina, the peak load is estimated to happen during the early hours of the day during the winter [65]. In this work, we assume planning reserves at 17%, as done in [65] for DEC and DEP.

To estimate if reserve requirements are met, a variable called capacity credit is used to represent the fraction of the total installed capacity of a process that can be relied upon during the peak load condition, also called Effective Load Carrying Capability (ELCC). In the determination of this variable two main sources are used in this work: The ELCC report prepared for Duke Energy in 2022 [66], and the average Equivalent Forced Outage Rate demand (EFORd) reported by NERC [62] from 2017-2021. Table 1 details the capacity credits used in this work.

For battery, solar, and wind technologies, reference [66] provides ELCCs for different brackets of installed capacity and possible synergies between technologies; this work does not consider this level of detail in the capacity expansion model optimization and assumes average values from this reference. It is important to remember that future load and generation conditions may change the critical load periods and, consequently, the technology capacity credit; however, this uncertainty is not considered here.

**Table 1:** Capacity Credit for Different Technology Types

|  |  |  |
| --- | --- | --- |
| **Technology Type** | **Capacity Credit (ELCC)** | **Reference** |
| Coal | 0.91 | [62]: (1- EFORd) |
| Petrol | 0.87 | [62]: (1- EFORd) |
| Natural Gas | 0.88 | [62]: (1- EFORd) |
| Nuclear | 0.98 | [62]: (1- EFORd) |
| Biomass | 0.91 | [62]: (1- EFORd Coal) |
| Hydro | 0.92 | [62]: (1- EFORd) |
| Pumped Storage | 0.94 | [62]: (1- EFORd) |
| Battery | 0.70 | Based on [66] |
| Solar | 0.05 | Based on [66] |
| Wind Onshore | 0.40 | Based on [66] |
| Wind Offshore | 0.70 | Based on [66] |

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|  |  |
| --- | --- |
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