E4220 – Energy System Economics

Wind Integration in ISO New England

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Introduction:

The following report details the Unit Commitment performed for the New England ISO (ISONE) in an attempt to analyze the difference wind integration can make on the overall system performance and cost, and also recommend a policy on how to decarbonize and achieve the best results for the overall electricity cost, generator revenue, and reduced carbon emissions.

The New England ISO is responsible for ensuring that electricity is provided to customers in the states of Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and most of Maine[1].

According to the EIA (US Energy Information Administration), electricity generation from Biomass, Hydropower, Solar, Nuclear, and Wind is considered carbon neutral or has a net carbon emission of zero. The methods employed by governing bodies to reduce the carbon emissions of different generators include providing incentives for increasing generation via renewable sources, shutting down CO_2-emission-heavy coal-fired power plants, or increasing the cost of generation by employing a carbon tax. For the incentives, a wind production tax credit may be used to promote further investments in wind projects in the region.

Analytic Framework

This section details the scenario analysis used in the unit commitment model. CVXPY & Gurobi were used to solve the minimization of the objective function, which was the total system cost for each day. The model included data for 76 generators, including different parameters such as maximum and minimum capacity, fuel type, minimum up and down time, ramp rates, etc. The analysis was performed each day for seven days (covering a 168-hour period for an entire week of demand); three levels of wind integration were considered: 2,000 MW as the base case, increasing up to 6,000 MW, and 12,000 MW of wind capacity.

In addition, further analysis was conducted on the impact various policy interventions can have on the operating cost of the system. The policies assessed were: the inclusion of a wind tax credit, a carbon emissions tax, and the early retirement of coal-powered power stations. Each scenario was then evaluated based on the total generation cost, the wind curtailment ratio, the profit received by the generators, and the average price of electricity.

[1] https://www.iso-ne.com/about/what-we-do/three-roles/

	Electricity Generation in million kWh	CO2 emissions in million metric tons	CO2 emissions in pounds per kWh
Coal	897,885	919	2.26
Natural Gas	1,579,361	696	0.97
Petroleum	19,176	21	2.44

Table 1: Total net electricity generation in the US in 2021, the resulting CO2 emissions, and the CO2 emission factor (pounds of CO2/kWh) for coal, natural gas, and petroleum

The carbon tax was modeled as an additional cost factor for all fossil fuel power plants proportional to the amount of CO_2 produced (depending on the fuel used). The approach for the carbon tax was to model it as a uniform carbon emissions price per metric ton of CO_2 produced, using the values outlined in Table 1, Column 3. Before the data from Table 1 could be used, it was first converted from lbs of CO_2 per kWh to Metric tons of CO_2 per MWh (for consistency with the units used, this method is elaborated in the Appendix). In the unit commitment code, these values were multiplied by the power generated by each generator to give the metric tons of CO_2 produced. Finally, the amount of CO_2 in metric tons was multiplied by the cost of carbon, which was fixed to a flat rate per metric ton of CO_2 produced to give the total cost of carbon emissions i.e the carbon tax, which was added to the objective function to be minimized.

The objective of the unit commitment was to minimize the overall system cost of electricity generation as modified by the factors for the additional scenarios. As a result, the objective function took the form in its original form:

$$Obj1 = \sum_i \sum_t \left(MRC_i g_{i,t} + NLC_i u_{i,t} + SUC_i v_{i,t} \right) + 9000 s_t$$

where Obj1 is the objective function for the system operating cost, consisting of the MRC or Marginal Cost of a given generator, NLC or the No-Load Cost of a given generator, SUC or the Start-Up Cost of a given generator, and s_t is the slack variable or the cost of the load-shedding for not meeting the demand at time t (time increments in units of one hour). To model and include the carbon tax, an additional factor can be added to the overall objective function:

$$Obj2 = CoC \sum_i \sum_t \lambda_i g_{i,t} - \theta_i g_{i,t}$$

where Obj2 is the total carbon emission tax, consisting of the CoC or the cost of CO_2 per ton, λ_i is the CO_2 emission amount per active power output, and θ_i is the permissible amount of CO_2 emission per active power output.[2] For this report, θ_i was set to 0. Within this scenario the objective function is then a minimization of the sum of Obj1 and Obj2:

[2] https://ieeexplore.ieee.org/document/9949884

$$\text{Obj} = \min\,(\text{Obj1} + \text{Obj2})$$

The Tax Incentive was modeled as a reduction in the overall cost function, proportional to the amount of wind generation. It is incorporated into the scenario specific objective function as shown in the equation below. For our model we used a wind production tax credit of $26/MWh.

$$Ob3 = \sum_i \sum_t \left(MRC_i g_{i,t} + NLC_i u_{i,t} + SUC_i v_{i,t} \right) + 9000 s_t - \left(\underline{\alpha}\, w_t \right)$$

where $\underline{\alpha}$ is defined as the wind production tax credit provided by the federal government, and w_t is the wind power generated at time t.

Lastly, the retirement of coal power plants was the final explored hypothetical scenario in which generators that use coal (their fuel type is marked as Bituminous or Sub Bituminous) are excluded from contributing towards meeting the power demanded for a given time step; this affects generators 6 through 16.

Results:

Wind Penetration

The following figures show the unit commitment results, for the daily total operating cost across the week, and the weekly total operating cost, with the 4 different wind penetration levels: No wind, 2,000 MW of wind, 6,000 MW of wind, and 12,000 MW of wind. The analysis shows that as the wind penetration levels increase, the daily operating costs for each day of the week are reduced, however, the amount reduced diminishes each day. This may point to fewer plants needing to be switched on for dispatch.

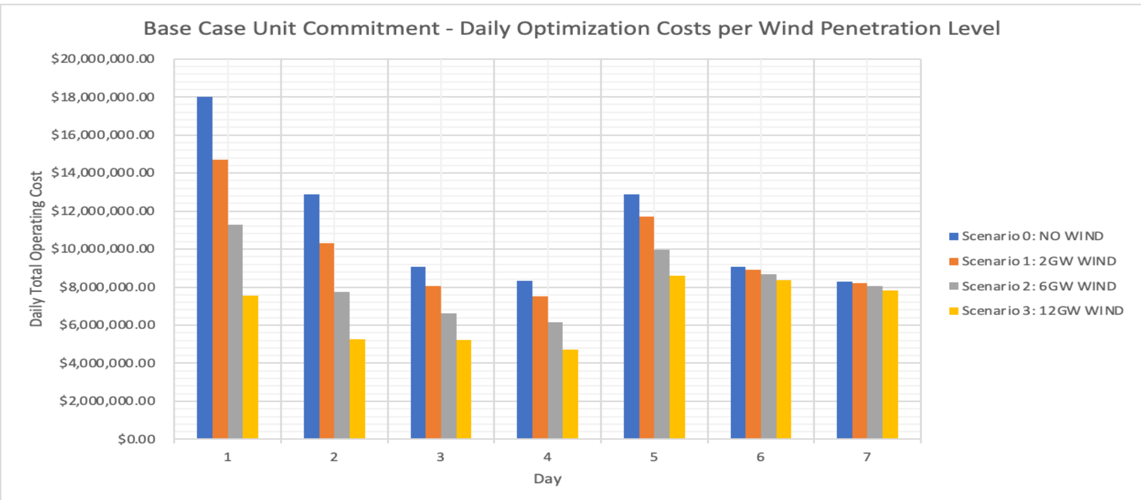

Figure 1: Daily Operating Costs, with different Wind Penetration Levels

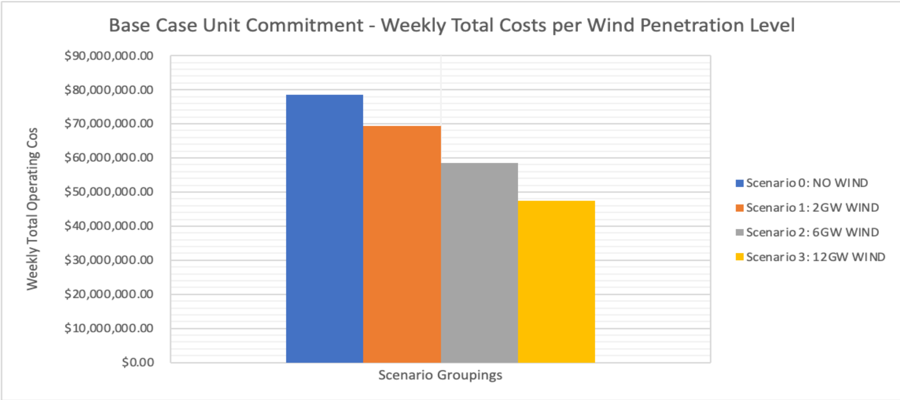

Figure 2: Total Operating Cost in the week, with the different Wind Penetration Levels

Coal Retirement

The following figures show the unit commitment results, for the daily total operating cost across the week, and the weekly total operating cost, with different percentages of coal power plant curtailment: 0%, 50%, 75%, and 100%. The wind penetration level for these was fixed to 2,000 MW. In this case, as more coal power plants are taken offline, the daily and weekly total operating costs are increased. The overall trend and increase in cost remains consistent throughout the week.

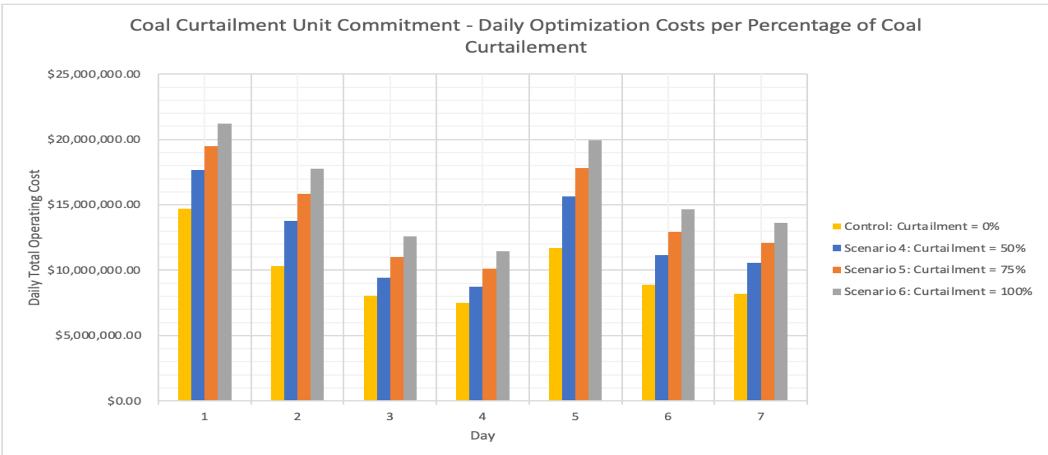

Figure 3: Daily Operating Costs, with the different levels of Coal Plant Curtailment

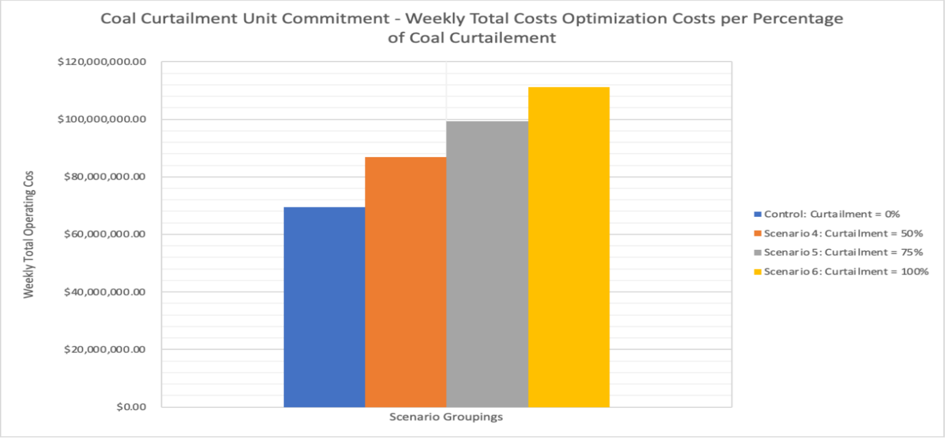

Figure 4: Total weekly operating costs across different values of coal retirement (note that wind capacity was fixed at 2000 MW)

Carbon Tax

The following figures show the unit commitment results, for the daily total operating cost across the week, and the weekly total operating cost, with different amounts of carbon tax: with a cost of carbon set to \$0, \$40, \$45, and \$50. The wind penetration level for these was fixed to 2,000 MW. The introduction of a carbon tax greatly increased the total operating cost, as is visible in the weekly total operating costs with and without the carbon tax.

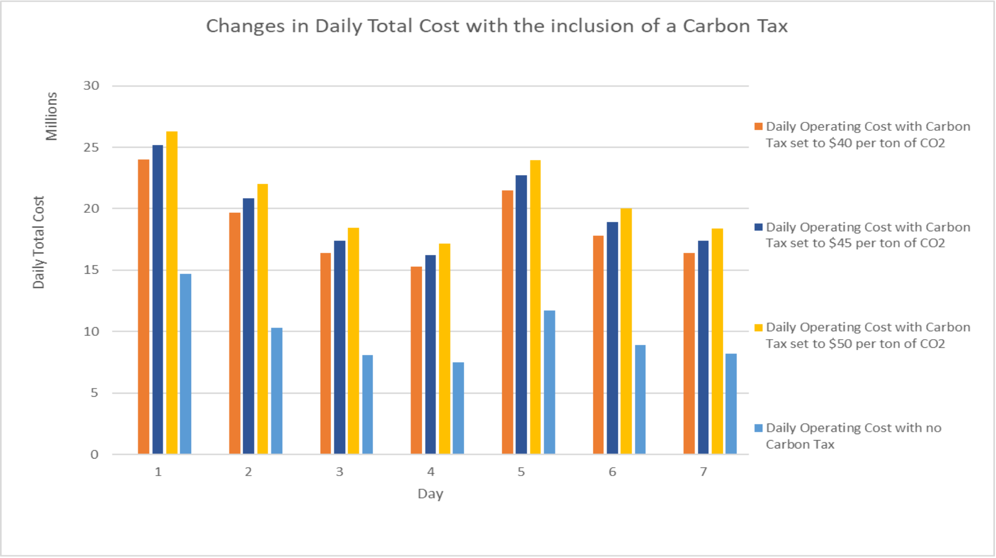

Figure 5: Daily Operating Costs, with the different amounts of Carbon Tax

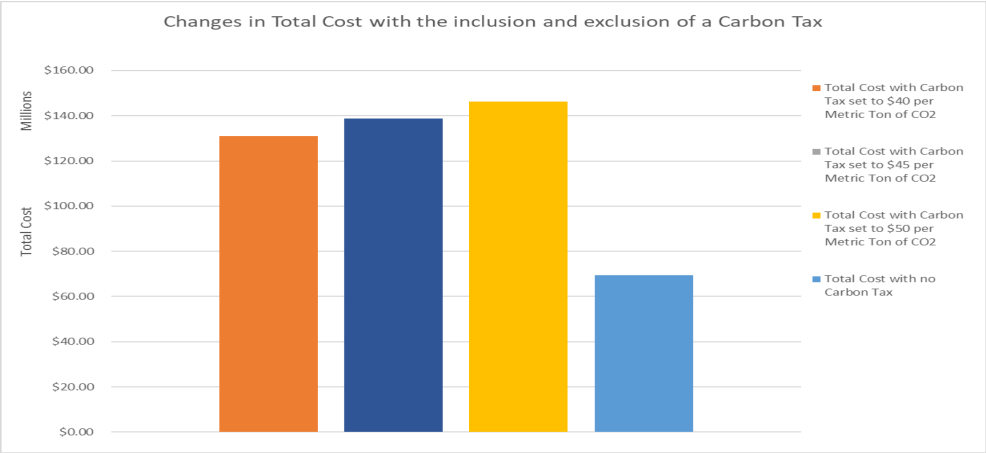

Figure 6: Total Operating Cost in the week, with the different amounts of Carbon Tax

Tax Incentives

The following figure shows the unit commitment results, for the daily total operating cost across the week with the wind incentive tax set to $26/MWh, with the different levels of wind integration: 2,000 MW, 6,000 MW, and 12,000 MW. The analysis shows that a tax credit reduces the daily operating costs by a few $100,000 for each day of the week. There was also a minimal amount of wind curtailment in our findings as the amount of wind capacity to be installed is marginal. However this amount would likely increase given a more significant availability of wind capacity for dispatch.

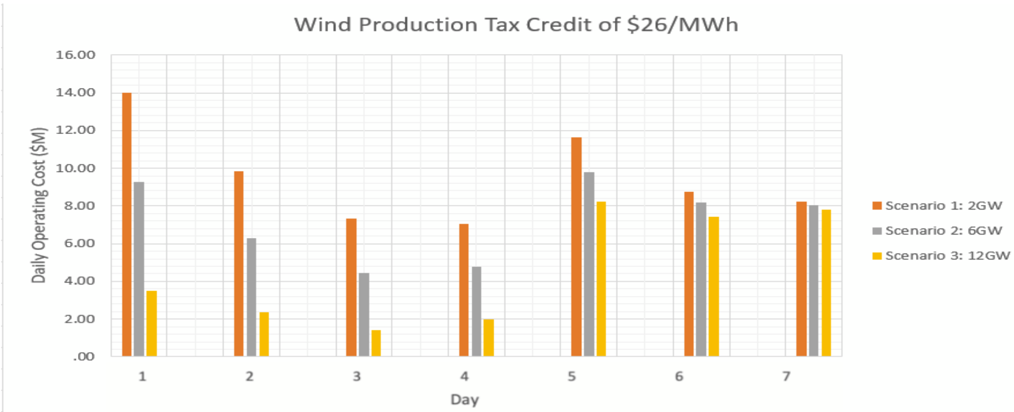

Figure 7: Daily Operating Costs, with the Tax Incentives

The following figure shows the unit commitment results, for the total amount of CO_2 emissions produced in the base case (all thermal generators running + 2,000 MW Wind Integration), also with the exclusion of the coal fired power plants, at 50% curtailment and at 100% curtailment. Interestingly, the CO_2 emissions actually increased with the 50% coal curtailment, on the 3rd and 4th day, indicating that the remaining coal plants, or other oil and natural gas plants would have to work more to make up for the lost power, actually producing more CO_2 as a result. However, the 100% coal curtailment does show a decrease in overall CO_2 emissions on each of the days.

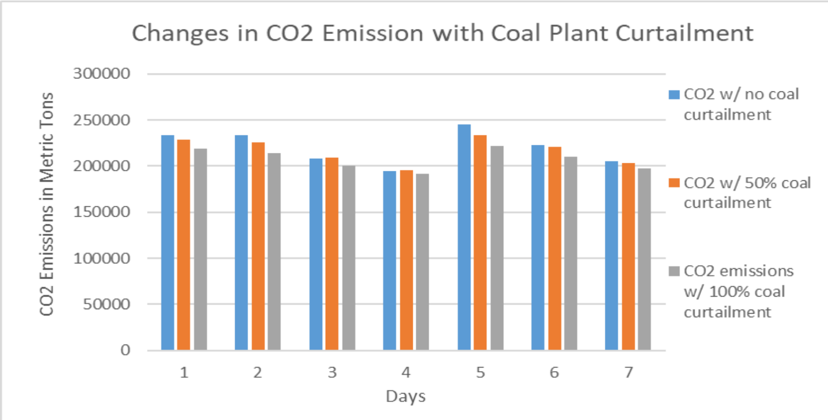

Figure 8: Daily CO2 Emissions with different levels of Coal plant curtailment

Generator and Wind Profits

This chart below shows the total generator and wind profit for each wind capacity scenario. The model shows that even though the overall system costs fall, the generator revenue and as a result, profit, also reduces considerably with increasing amounts of wind penetration.

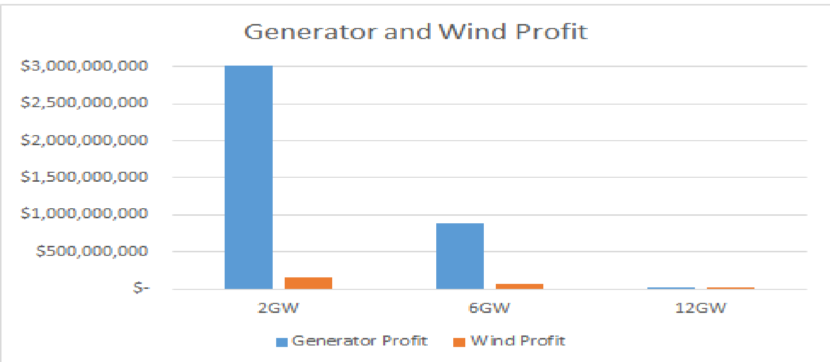

Figure 9: Generator and Wind Profits for each scenario

It should be noted that the average price of electricity ($/MWh) is extracted from the dual variable λ[t] of the load balance constraint when all binary decision variables are fixed (u,v, and z all retain values calculated during initial modeling). Utilizing the average of this parameter over the course of a day:

$$Avg\,\lambda = 1/24 \sum_{t}^{24} \lambda[t]$$

is still dubious as we noticed significant outliers within the marginal electricity price and an uncharacteristic amount of slack generation provided (depicted in Figure 10 & Figure 11 below). Given that the generator revenues and subsequent profits (and the wind profits) incorporate this price, further confirmation is required to verify the high generation profits shown in Figure 9. Nevertheless, we thought it important to include our methodology.

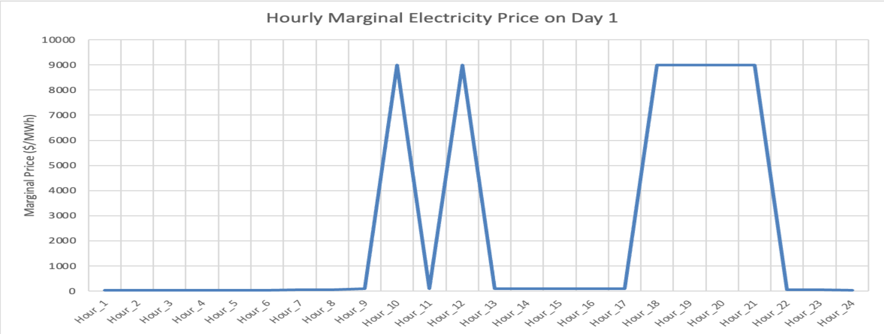

Figure 10: Hourly Marginal Electricity Prices for day 1

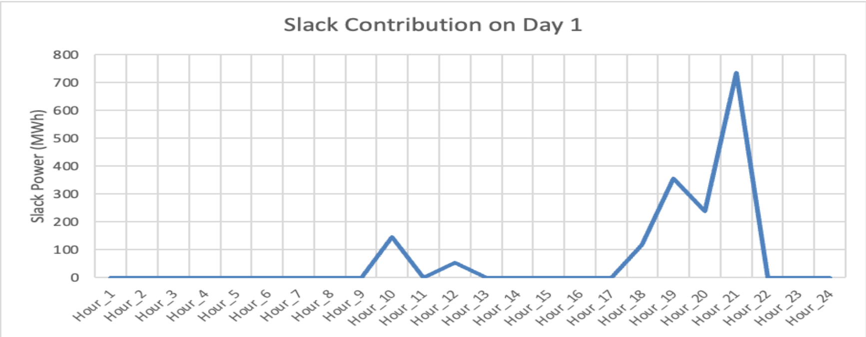

Figure 11: Hourly Slack bus contributions for day 1

Conclusion and Recommendations

Based on the results, the integration of wind power plants into the generation would help reduce the overall system cost. The best-case scenario would be for ISO-NE to integrate between 6 GW and 12 GW of wind capacity in addition to a wind production tax of $26/MWh and a coal curtailment policy of 50%. This combination minimizes the electricity cost and system-wide carbon emissions, whilst providing a suitable amount of generator revenue.

However, to achieve the least amount of carbon emissions, the best policy would be to enact a $45 carbon tax per metric ton of CO_2 produced, as well as 100% coal curtailment. While this would greatly increase the overall total cost of the system, it would decrease the total carbon emissions of the system.

Appendix:

Supplemental information (Carbon Tax)

In 2021, it was found that about 61% of total annual U.S. utility-scale electricity generation, produced by burning coal, natural gas, and petroleum fuels, accounted for 99% of CO_2 emissions associated with utility-level electricity production. Furthermore, the amount of carbon emissions produced per kWh at any specific period of time by the power plant from electricity generation can vary by their efficiency (affected by factors such as the age of the plant), and the fuel type used.

With the introduction of a carbon emissions tax, the government sets a price that generation companies must pay for every ton of greenhouse gas they emit. The per-ton fee starts at a modest level and slowly increases over time. To circumvent this, utilities undertake practices such as switching fuels to those that produce less CO_2/kWh or adopting new technologies, to reduce their emissions to avoid paying a greater amount of tax.[3]

The fuel types provided in the data were as follows: NUC = Nuclear, BIT = Bituminous (higher quality), and SUB = Sub Bituminous (lower quality) – Coal, RFO = Oil. NGXX = Variants of Natural Gas

To convert the lbs per kWh to Metric Tons per MWH, the data from Table 1 had the following conversion performed:

$$\frac{lbs}{kWh} \times \frac{1\ MT}{22014\ lbs} \times \frac{1000\ kWh}{1\ MWh} = \frac{1\ MT}{2.204\ MWh}$$

As a result, coal had a factor of 1.0254 MT/MWh, oil had a factor of 0.44011 MT/MWh, and natural gas had a factor of 1.10708 MT/MWh.

Determining the best price for the carbon tax has recently proved to be challenging for different countries around the world. While generators in some countries like Ukraine only pay \$0.30 per ton of CO_2, Sweden has a carbon tax of approximately \$200 per ton of carbon emissions[4]. For the US, the appropriate carbon tax price was estimated to be \$36 in 2015, and \$46 per ton in 2025, with an increase of at least 1% to 20% per year, to reduce carbon emissions by close to 40%. For this Unit Commitment, the Cost of Carbon was set to \$40, \$45, and \$50, to see the effects of the Carbon Tax on the Total Operating Cost.

Approach to the problem and Methodology

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[3] https://www.c2es.org/content/carbon-tax-basics/

[4] https://www.brookings.edu/research/why-the-us-should-establish-a-carbon-price-either-through-reconciliation-or-other-legislation/

The methodology adopted to minimize the system cost (our objective function) was to solve a unique optimization problem to meet the constrained set of physical and regulatory requirements necessary to execute a unit commitment for each day and then pass the decision variables representing the last hour of generation and unit commitment (g0 and u0) to the next day for use. Furthermore, our objective functions consider both the linear and quadratic costs associated with each generator's behavior.

Included Constraints:

1. $$\mathrm{Gmin}_i u_{i,t} \leq g_{i,t} \leq \mathrm{Gmax}_i u_{i,t}$$

2. $$-\mathrm{Gmin}_i z_{i,t} - \mathrm{RR}_i \leq g_{i,t} - g_{i,t-1} \leq \mathrm{RR}_i + \mathrm{Gmin}_i v_{i,t}$$

3& 4. $$v_{i,t} - z_{i,t} = u_{i,t} - u_{i,t-1}$$ $$v_{i,t} + z_{i,t} \leq 1$$

5. $$\sum_i g_{i,t} + w_t + s_t = D_t : \lambda_t$$

6. $$\sum_i r_{i,t} \geq (3\%)D_t + (5\%)w_t$$ $$r_{i,t} \leq \mathrm{Gmax}_i u_{i,t} - g_{i,t}$$ $$r_{i,t} \leq RR_i$$

7. $$w_t \leq \alpha_t W$$

Excluded Constraints:

1. $$\sum_{\tau=\max\{t-\mathrm{Tup}_i+1,1\}}^{t} v_{i,\tau} \leq u_{i,t}, t \in \{\mathrm{SU}_i, \ldots, T\}$$ $$\sum_{\tau=\max\{t-\mathrm{Tdn}_i+1,1\}}^{t} z_{i,\tau} \leq 1 - u_{i,t}, t \in \{\mathrm{SD}_i, \ldots, T\}$$

2. $$\sum_{t=1}^{\mathrm{SU}_i} u_{i,t} = \mathrm{SU}_i$$ $$\sum_{t=1}^{\mathrm{SD}_i} u_{i,t} = 0$$

Teammate Contributions

David Bongiorno - Wrote the majority of the code for this assignment (providing the framework for the unit commitment optimization in an iterative fashion, passing the decision variables between days, using the quadratic term, etc.) and endeavored to provide methods of export for the results. My particular scenario was that of coal retirement and generated the plots for that section and the basecase wind penetration scenario. I assisted a bit with the final editing and writing of the report.

Zain Hussain - Worked on the majority of the report, covered the scenario for the Carbon Tax and its aspects in the code, the report, and the results, and the reduction in the amount of CO2 emissions vs the Coal Curtailment.

Cyril Darku - Implemented the reserve constraints for the unit commitment model. Modeled and plotted the results of the wind tax incentive scenario. Plotted the generator and wind profit results for each of the 3 scenarios and wrote and edited portions of the report.