A Modeling Framework for the Future New England Grid System with Increasing Renewables

Trisha Ray

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Contents

1 Background

The New England grid system is overseen and operated by ISO New England (ISO-NE), the independent system operator for New England. The three main functions of ISO-NE is (1) to ensure that the grid is operating at all times, (2) to run the wholesale electricity market for buying and selling electricity, (3) to create a plan for the future New England power grid. This last critical function falls under the category of system planning. System planners at ISO-NE are in charge of planning for long term changes to the grid to ensure that the grid remains reliable up to ten years into the future. System planners have to find solutions to ongoing problems and potential threats that cannot always be solved in real time by system operators. One of the potential threats that the New England grid system is currently facing is a fuel security issue because of shortages in natural gas. As discussed in ISO-NE's 2018 Regional Outlook, there is a high chance of natural gas shortages during periods of extreme cold in New England which leaves the grid vulnerable to blackouts.

The New England fuel security issue is what originally motivated this project. The goal of this project is not to find a solution to the New England fuel security issue, but to explore a means by which to model the conditions of the problem and analyze it in further detail. My focus is to model the New England grid system in the winter when the high prices and unreliability of natural gas might make other types of fuel sources more favorable. In addition to the fuel security issue, system planners at ISO New England are having to understand how an increase renewable energy will affect the grid as well. Operating the grid with renewables is quite different than traditional sources of energy since renewable energy is intermittent and non-dispatchable. These two issues are the basis of how I chose to design my future New England grid system. The overall objective of my independent research project for this year was to create a modeling framework to understand how increasing renewables and retiring coal, oil, and nuclear power plants will affect the New England grid system. The majority of this paper will cover how I built a modeling framework using MATPOWER MOST. The last section of the paper will look at the types of results that can be obtained from the model I created.

2 Model Data

The IEEE 39 Bus Case System is known for being a representation of the New England grid system with 10 generators and 46 lines. I used this bus case system as a starting point for modeling the rapidly changing New England grid system. The first initial challenge in using the IEEE 39 Bus Case System was understanding

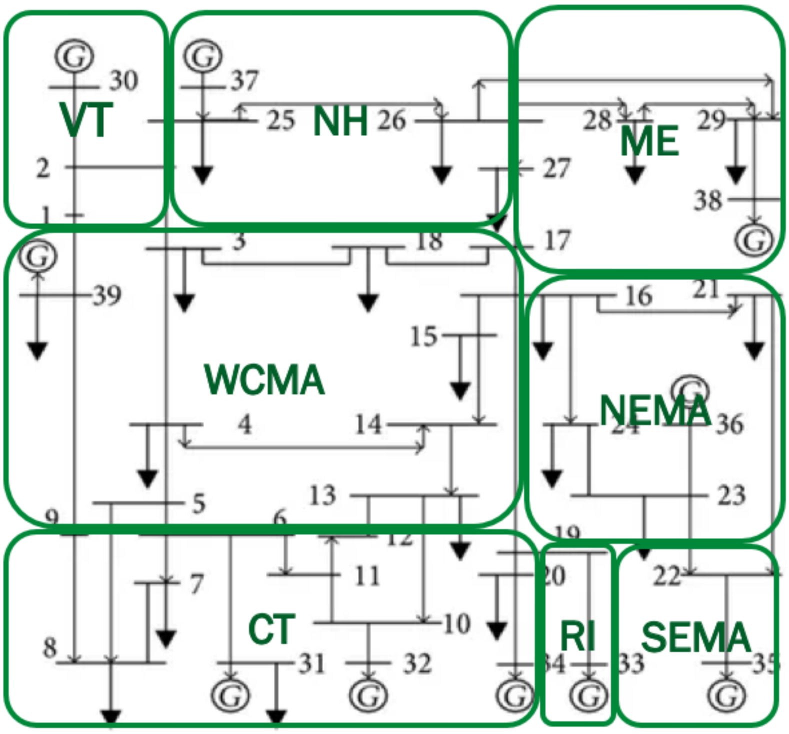


Figure 1: Load Zone Breakdown of IEEE 39 Bus Case System

how the system represented the actual New England Grid System. The actual grid system is broken up into eight different load zones. The eight load zones are geographically grouped together and represent an aggregate of load nodes that are used for pricing in the wholesale electricity market. These load zones are listed on the ISO-NE website. The ISO-NE website also provides a system diagram of all the New England high voltage lines and buses, organized by load zones they fall under. This system diagram along with the assistance of Professor Lindsay Anderson and Professor Judith Cardell allowed me to identify where the eight New England load zones would be approximately located on the IEEE 39 Bus Case System. The IEEE 39 Bus Case System broken down into load zones is shown in Figure 1.

In the original IEEE 39 Bus Case System, the 10 generators modeled are either hydro-power, nuclear, or fossil fuels. As the purpose of this project is to understand the affect of renewables on the grid system, the generation mix needed to be updated. Searching through the publicly available information on the ISO-NE website, I found that the results from the Forward Capacity Auction provide the most granular data for modeling the future New England grid system. The remainder of this section will discuss how I updated the generation mix using the Forward Capacity Auction data,

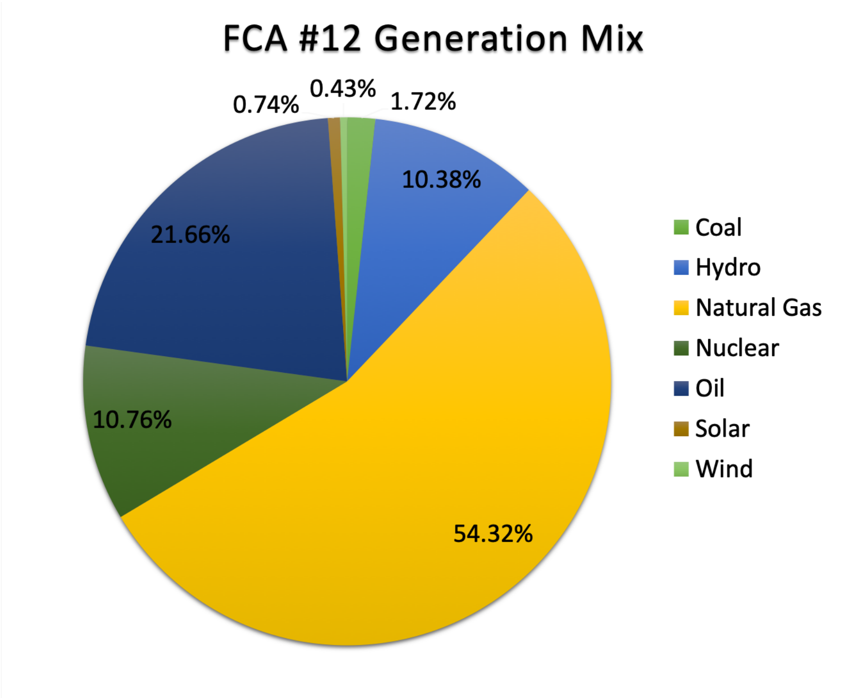


Figure 2: FCA 12 Generation Mix Pie Chart

following by how I updated the generation cost and the profiles for changing wind, solar, and load patterns. These were the largest pieces to my model that needed to be created or updated in order to represent the future New England grid system.

2.1 Forward Capacity Auction

The Forward Capacity Auction (FCA) is an annual auction that ISO-NE holds to ensure that the grid has sufficient capacity up to three years into the future. The results of each auction are published on the ISO-NE website. The results break down the generation type for each of ISO-NE's eight load zones. For this reason, I based my model's generation mix off of the results from FCA 12 which secures capacity for ISO-NE for the 2021-2022 commitment period. These were the most recent auction results at the time I was building my model. The breakdown of the generation mix from this auction is shown below in Figure 2 and 3. Looking at the actual breakdown of the generation from the FCA 12 results, there are a significant number of generators that qualified in the auction. In order to represent all of these generators as the 10 generators in the 39 bus case, I took the aggregates of all the generation of each load zone and equally divided that generation amongst

FCA 12 CSOs (MW)									
	CT	ME	NEMA	NH	RI	SEMA	VT	WCMA	Grand Total
Coal				533					533.32
Hydro	120.789	514	0	529	0.23		57	2001	3222.831
Natural Gas	4842.338	1557	2414	1235	2380	3246		1197.3	16872.013
Nuclear	2095.855			1247					3342.93
Oil	2756.697	844	783	483		1204	133	523.79	6727.485
Solar	39.219	42	9.49	32.5	8.62	25.98	11	60.294	229.145
Wind		65.2	0.17	28.3	6.83	2.775	22	6.852	132.363
Grand Total	9854.898	3022	3206	4089	2396	4479	224	3789.2	31060.087

Figure 3: FCA 12 Generation Mix Table

the generator buses in that zone. In addition, since the bus case is not designed to handle the actual capacity of the New England grid system, all of the generation capacity was scaled down to 20% of the actual generation.

2.2 Generation Costs

Once the generation mix was established for the model, I needed to determine of the generation costs for the different types of fuel. Since the majority of the generation cost is the fuel cost, my model assumed that the generation cost of renewables is zero. For the remaining types of generation, the generation costs were obtained from the U.S. Eneregy Information Administration (EIA). The EIA published the following graph as seen in Figure 4 on the average fossil fuel spot prices. As can be seen from the graph, the fossil fuel prices tend to stay the same throughout the year. The one exception to this is the natural gas prices that spike in the winter. As stated before, there is a shortage of natural gas in the winter when the demand for natural gas increases. Natural gas is given priority to the heating sector to ensure that there is adequate heat in all buildings and houses in the region. This means that the electricity sector only receives what is left of the natural gas after demand is satisfied in the heating sector. This can lead to high prices and/or inadequate fuel in the electricity sector. The cost of fuel for nuclear power plants, which was not in the graph above, was estimated from another EIA source [1] at approximately $7.50/MW.

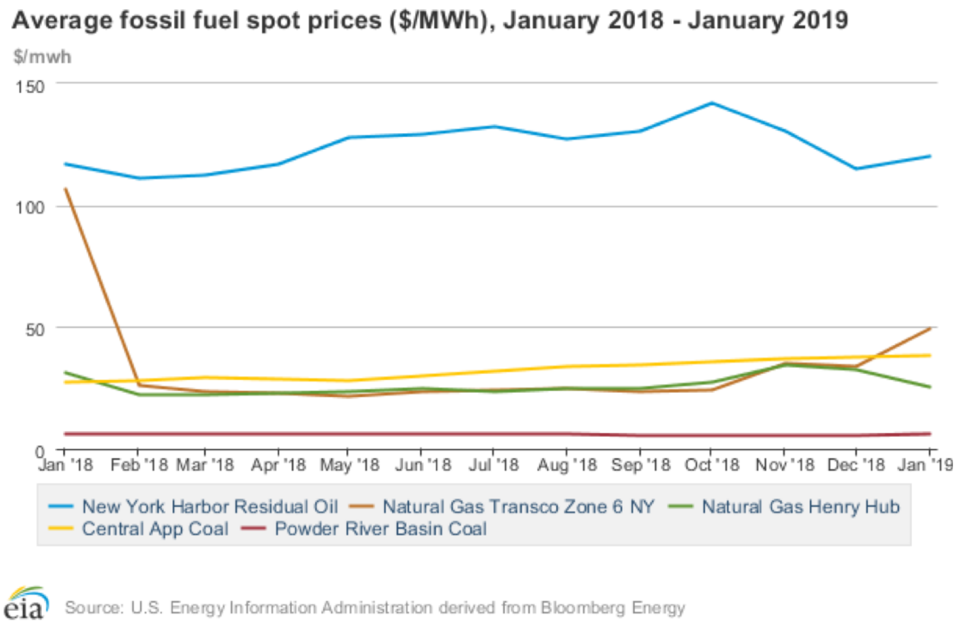


Figure 4: Average Fossil Fuel Spot Prices ($/MWh)

2.3 Profiles

The last main component to my model that needed to be created is the profiles. In order to successfully run an unit commitment problem, the model needs data on how the system will change from hour to hour in order to decide which generators to commit. The profiles function in MATPOWER MOST allows us to provide deterministic data on the load, wind, and solar profiles over a 24 hour period.

2.3.1 Load Profile

In order to model the load of New England, I needed data on the hourly load for the eight different load zones in order to run the unit commitment problem. ISO-NE provides this information in [3] with the title of "2019-2028 SMD Load Zones Hourly Load Forecast." This text file lists the actual forecasted megawatts for each hour of every load zone. Since my model is a scaled version of the total energy capacity of the New England grid system, I took a 24-hour load profile to be a percentage of the maximum load of a certain day. The data I used in my model is for the first day in January 2022. Using the data from ISO-NE, I then determined which buses belongs to which load zone. Using Figure 1, the breakdown of buses to load zones is shown below. As mentioned before, the actual load capacity is too great for the scale of

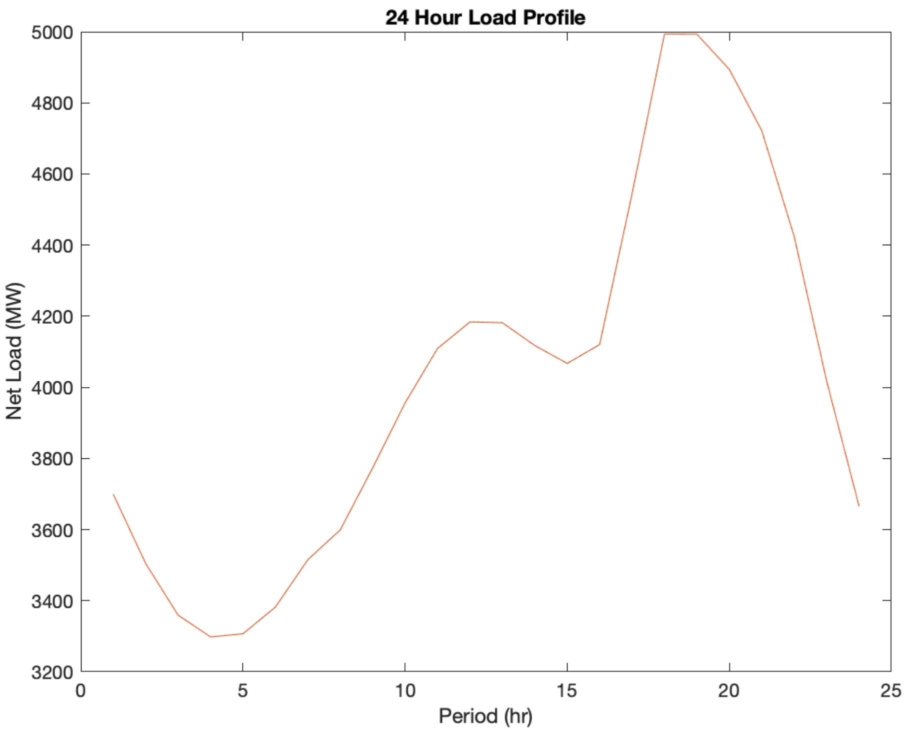


Figure 5: Scaled Load Profile of New England for January 1, 2022

this model, so in order to scale down the actual capacity, I took the percentage of load in each zone and multiplied it by 81% of the scaled down capacity from the FCA generation data. This ensured that the scale of the generator capacity and the load forecasts were the same, and that the power flow problem would converge. The actual 24 hour load profile can be seen in Figure 5.

Load Zone	**Buses**
Connecticut	8,7,9,6,12,11,10,20
NEMA	16,21,24,23
WCMA	3,18,15,4,14,5,13
SEMA	22
Rhode Island	19
Vermont	1,2
New Hampshire	25,26
Maine	27,28,29

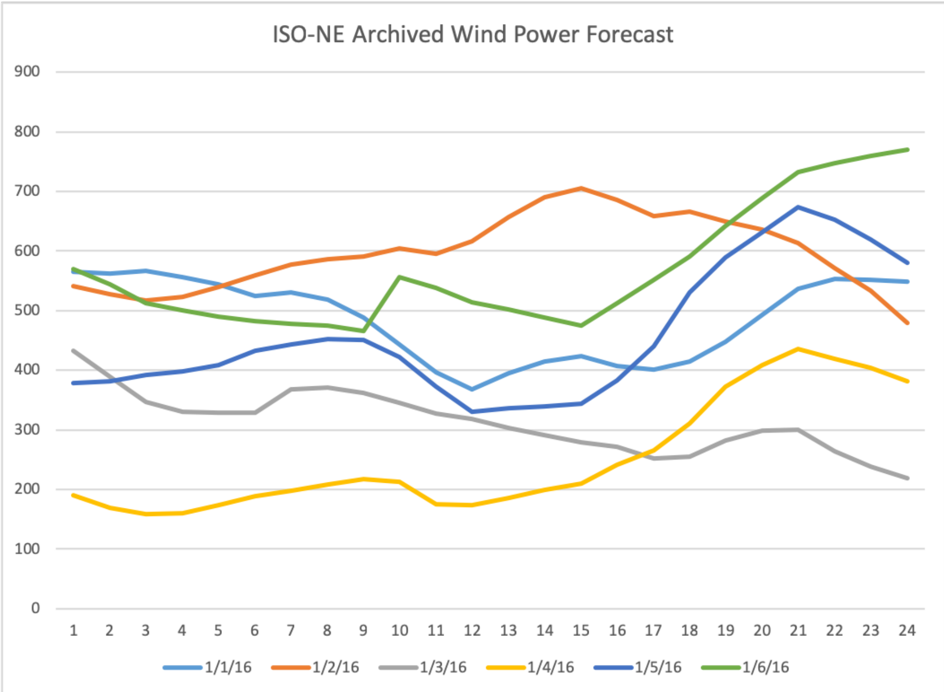


Figure 6: First Six Days of January 2016 Wind Forecast

2.3.2 Wind Profile

In order to create a wind profile for my model, I used the Seven-Day Wind Power Forecast Archive for the first week of January in 2016. ISO-NE does not publish hourly forecasts for wind that go as far as 2022, so I decided to base my predictions on historical data. As Figure 6 shows, wind patterns are very unpredictable. However, since my model for this project is deterministic, I used this data to gain a general understanding of how varying wind patterns affect the unit commitment problem. Due to the unpredictability of wind power, this is an area of my model that can be improved using stochastic modeling.

When implementing wind power plants into my model, I used the data from FCA 12 again to determine the amount of wind capacity in each of the different load zones. Then using the Seven-Day Wind Power Forecast data, I found the hour with the maximum wind power for each day, and then calculated the percentage of wind power to the maximum wind power for all 24 hours. Using this percentile wind profile, I was able to scale down the wind capacity to match the scale of the rest of the generators.

2.3.3 Solar Profile

In order to create a solar profile for my model, I used PVWatts hourly data for cities in the eight different load zones. The cities chosen to represent the solar profile for each load zone is shown below. The reason I created a different solar profile for the different load zones is because the solar irradiation for these different zones does differ enough that a uniform solar profile would not be as accurate. All of the solar profiles have the standard bell shape curve and no power output at night. However, as seen in Figure 7, Vermont has lower solar irradiation than NEMA and the rest of the solar profiles lie in between these two zones.

Load Zone	**City**
Connecticut	Berlin
NEMA	Boston
WCMA	Springfield
SEMA	Barnstable
Rhode Island	Providence
Vermont	Rutland
New Hampshire	Manchester
Maine	Bangor

In the next section I will discuss how I implemented my updated IEEE 39 bus case into MOST.

3 MOST Modeling Framework

The most technically challenging part of this project was understanding how to correctly input my model data into MOST. MOST is a publicly available framework for solving generalized steady-state electric power scheduling problems. MOST stands for MATPOWER Optimal Scheduling Tool. More specifically for the scope of this project, MOST can solve deterministic, multi-period economic dispatch and unit commitment problems. MOST can also solve problems with uncertainty in demand and renewable generation, although that is outside the scope of this project. Both user manuals [7] and [6] provided detailed documentation on how to build a model using MOST. The main MOST function is most() which can be called in MATLAB to solve a large variety of power flow problems whether stochastic, multi-period, etc. In order to run the most() function, a MOST Data struct needs to first be created.

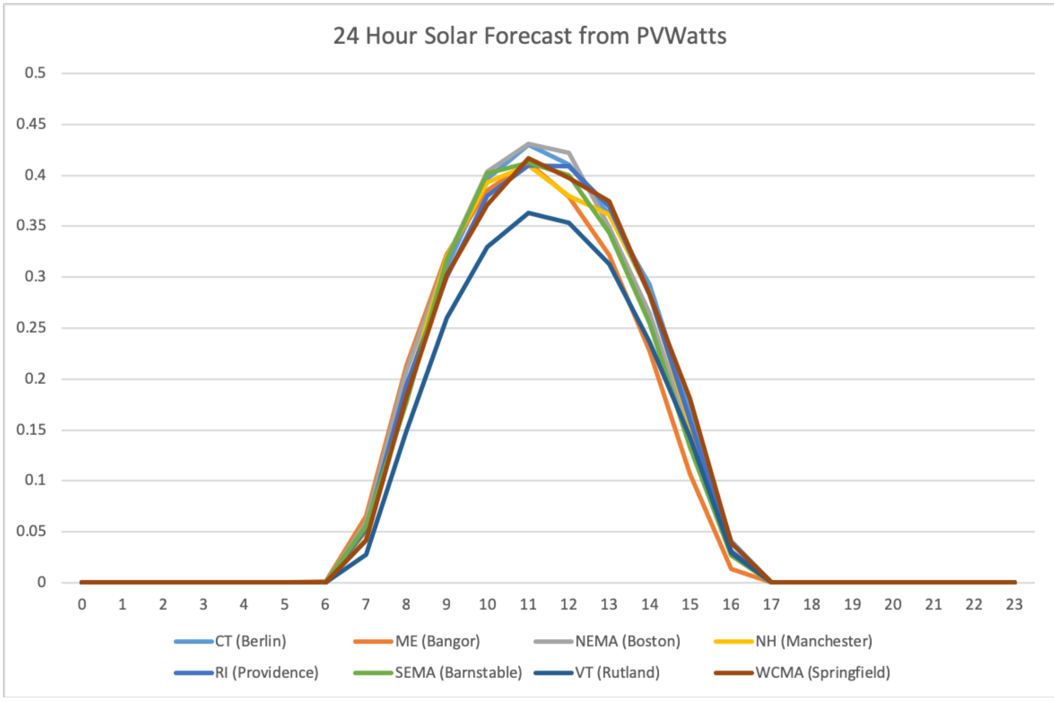


Figure 7: 24 Hour Solar Forecast from PVWatts for Each Load Zone

3.1 Input Data

The input data for the model that is being run must all be loaded into a MOST data struct. This input data is broken down into six different types of files and data structures as seen in the MATLAB code below.

```
mdi = loadmd(mpc, transmat, xgd, sd, contab, profiles);
```

The six different inputs for the loadmd function are not all required. The only required input is the mpc file that is the MATPOWER case. Every MATPOWER case has bus data, generator data, and branch data at the minimum. The case can also have generation cost data which is included in this model as well as reserve data. Since I had to update the data in the IEEE 39 Bus Case (case39.m), my main MATLAB file first loads the original case39.m file and then reads excel data with the updated values for the model. All of the excel data and code for this project can be found here: https://github.coecis.cornell.edu/tr272/UndergraduateIndependentResearch.

Starting with the generator data, the following parameters of this field were updated: the real power output, reactive power output, maximum reactive power output, minimum reactive power output, maximum real power output, the ramp rate for 10 minute reserves, and the ramp rate for 30 minute reserves. I updated the maximum real power output information using the scaled down generation mix from Section 2.1. The minimum real power output, based off of [4], is 5% of full load for hydro power plant, 20% of full load for natural gas (combined cycle), and 30% of full load for coal and oil power plants.

When determining the maximum and minimum reactive power output, I assumed that all generators would be able to satisfy the typical requirement of 0.90 lag and 0.95 lead power factor as stated in [5]. This means that the maximum reactive power output of each generator will be 48% of the maximum real power output and the minimum reactive power output will be the negative of 33% of the maximum real power output. The ramp rate refers to load-following ramping. This is how quickly a power plant can increase or decrease its current megawatt output to react to changes to the demand and/or to contingencies. For simplicity, this models assumes that the ramp rate for 10 minute reserves and 30 minute reserves are the same. In reality, a larger ramp rate would be expected for 10 minute reserves since the system needs to recover from a contingency faster. The ramp rate data for the different types of generation were obtained from [2].

Next, in order to update the bus field, the real power demand and reactive power demand for each bus had to be updated. The information for the real power demand is updated using the information from Section 2.3.1. In order to update the reactive power information, I made the assumption that the reactive power at each load bus is 30% of the real power. The last field for the mpc input that I updated was the generation cost according to Section 2.2. The generation cost data is stored in the gencost field. It includes the variable cost of producing power per megawatt as well as the start-up and shutdown costs.

The extra generation data or the xgd file is another input into the loadmd function. The extra data that I used in my model are the commitment key, the commitment schedule, the minimum up time, the minimum down time, and the positive and negative reserve price and quantity. The commitment schedule and commitment key parameters specify if a generator is available for unit commitment or if it must always be running as in the case for nuclear and renewables. The minimum up time and the minimum down time refers to how long it takes a generator to start up and shut-down. Hydro-power plants have a really fast start-up time while nuclear power plants can take an entire day to start-up or shut-down. In this model, nuclear, wind, and solar power plants will always be running, so their minimum up and down time won't matter. For the rest of the generation types, including this information in the unit commitment problem is essential for understanding which types of power plants will be able to come online or go offline as the power demanded changes throughout the day. Based off of [4], for my model it takes a combined cycle gas turbine 2 hours to start up while oil and coal power plants take about 3 hours to start up. The last extra generation data I included is information for load following ramping reserve. The ramping rate for these reserves were discussed above, but not the price and quantity of these reserves. Load-following ramping reserves are used regulate voltage fluctuations in the time range of 10 minutes to an hour. Since our load profile is changing every hour, these reserves are crucial to the unit commitment problem. Without publicly available data on the actual reserve quantity and prices, I assumed all generators to have 25% of their maximum power output as the reserve quantity and a negligible price for the reserves based on other cases I studied.

One quick note I would like to make is that the mpc and xgd data for wind and solar power plants are included separately from the other generators using the addwind function that MOST provides. The parameters that are updated are the same as for all the other types of generation. The only difference is that the addwind function automatically names all the generators as wind power plants, so the solar power plants had to be renamed as solar. The reason I chose to add the renewables separately from the other generators using the addwind function is so that creating 24 hour profiles for their power generation would be simpler.

The last type of input in my model that is included in the loadmd function is profiles. As mentioned in Section 2.3, there are three different profiles that need to be included: load, wind, and solar. These profiles are each separate structs that get loaded into the correct format using the getprofiles function. The wind struct used in the model is shown below.

```
windprofile = struct( ...
    'type', 'mpcData', ...
    'table', CT_TGEN, ...
    'rows', [1 2 3 4 5 6 7 8 9], ...
    'col', PMAX, ...
    'chgtype', CT_REL, ...
    'values', [] );
```

The 'type' parameter assigns the target data structure to the fields in mpc. If there is mpc data as a parameter in the getprofiles function, this is the data that the struct refers to. Otherwise, it will refer to the mpc data in the loadmd function. Then, the 'table' parameter narrows down the search to what the profile is changing to the gen field in mpc. The 'rows' parameter determines which generators will be changed. Then, the 'col' parameter determines which column in the gen field is being changed. In this case, it is the maximum real power output. The 'chgtype' parameter determines that the maximum real power output data will be scaled by the percentage in the 'values' parameter.

Below is a summary of all the files needed for the input data: There is a main file, three profile files, two files for renewable data, and a file for the extra generation data for the traditional generators.

Input Files
main.m
solar_profile_39.m
wind_profile_39.m
load_profile_39.m
wind_39.m
solar_39.m
ex_xgd_39.m

3.2 Output Data Plots

The output data that the most function returns is a struct with a large amount of data that is hard to interpret in this form. To interpret the data more easily, there is an in-built function in MOST that graphs the unit commitment of all the generators that are available to be committed. In order to visualize the actual megawatts outputted by all generators every hour of the unit commitment problem, I created a plot_generation function. In order to visualize the locational marginal prices for the unit commitment problem, I created a plot_lmp function. Lastly, I created a function to graph the load profile to ensure that the profile was correct. These different plots are shown in the next section with the 2022 Model Results.

4 2022 Model Results

Putting all this data together, I ran my model to represent the first day of the year in 2022. In order to break down the effects of different inputs of my model, I ran the same model with no constraints, and then added a constraint one by one and then reran the model each time. This method of analyzing my results is taken from the tutorial section of the MOST 1.0 User's Manual. First, the model is run as an economic dispatch problem without ramping, startup/shutdown costs, or minimum up and down time. Then, the model is run as a DC optimal power flow problem without the additional constraints. Then, the model reruns after adding startup and shutdown costs, reruns again after adding minimum up and down time constraints, and finally reruns one last time after adding ramping constraints. Overall, the model is run five different times.

4.1 Economic Dispatch

In order to solve an economic dispatch problem, MOST allows you to turn off the DC network and ignore the line constraints. The top graph in Figure 9 shows the no network unit commitment results. Since oil has the highest generation costs, these types of generators are committed less often. The results from the economic dispatch show which generators are able to provide the cheapest energy based on mainly their generation costs alone. As seen in the bottom graph in Figure 9, the locational marginal price increases as the demand increases throughout the day.

4.2 DC Optimal Power Flow with No Constraints

By adding line constraints into the model, the model becomes a DC optimal power flow problem. The top graph in Figure 10 shows the effects of adding this constraint. With the DC network included, optimizing the unit commitment problem has to include considering the line flow limits on all the branches. Adding line constraints will split the nodal prices if there is congestion as seen in the bottom graph in Figure 10.

4.3 DC Optimal Power Flow- Add Startup/Shutdown Costs

Next, I added startup and shutdown costs. By adding this constraint, it becomes less economical to change the unit commitment of a generator too frequently. For nuclear plants the startup and shutdown cost is so great that they never want to switch offline unless its necessary for maintenance. As stated below, my model assumes that nuclear power plants are always running so these costs can be ignored. As seen in the top graph of Figure 11, the unit commitments of different generators are overall for a longer duration with less generators switching between online and offline throughout the day.

4.4 DC Optimal Power Flow- Add Minimum Up/Minimum Down Time

The next constraint I added is the minimum up and minimum down time. While adding the startup and shutdown costs makes it economically unfavorable to switch generator between offline and online, the minimum up and minimum down time constraints make it physically impossible for some types to generation to come online or go offline in an hour. Similar to the results from adding startup and shutdown costs, the top graph of Figure 12 shows that overall generators are staying online for longer.

4.5 DC Optimal Power Flow- Add Ramping

The last constraint I added is ramping. As seen in the bottom graph of Figure 13, ramping causes a spike in the locational marginal price around hour 18. This can be due to the ramping constraints that increases line cogestion and the number of generators that have to be online during that time. Since this time is during peak load, it makes sense that the price are the most expensive then.

As mentioned in Section 3.2, in order to analyze the results further than only seeing if a generator was committed during a certain hour, I used the plot_generation function to analyze the actual megawatt output of every generation during the first day of 2022. The output of the plot_generation function when all the constraints are included in the model are shown in Figure 8. The plot_generation function is used to make sure the results make sense. For example, looking at the results from Figure 8, I know that the megawatt output of the nuclear power plants make sense since they are always running without any ramping. On the other hand, the results from the unit commitment plot and the LMP plot provide information that is easy to compare with the different runs. These plots allowed me to understand the effects of the different constraints.

5 Conclusion

Building a model for the future New England grid system was the most challenging and time-consuming part of this project. Analyzing the results from a day in January 2022 provided preliminary results for how the grid might look in the future. The results in this project are quite preliminary since the majority of time was spent building the model in MOST. As seen from the results, there were no fuel security issues as discussed in the introduction. This is not because the problem is solved using my model. The results for the model I ran only accounted for the fuel security constraint in higher natural gas fuel prices. It did not account for an actual shortage of fuel. However, with this model built, it will be easy to extend the results presented in this paper and analyze different scenarios that the New England grid system may be facing with fuel shortages in the future. In addition, MOST allows for stochastic modeling which can be implemented to see how uncertain wind, solar, and load can affect the unit commitment problem. Overall, I hope this model allows for further research using MOST to analyze the future New England Grid System.

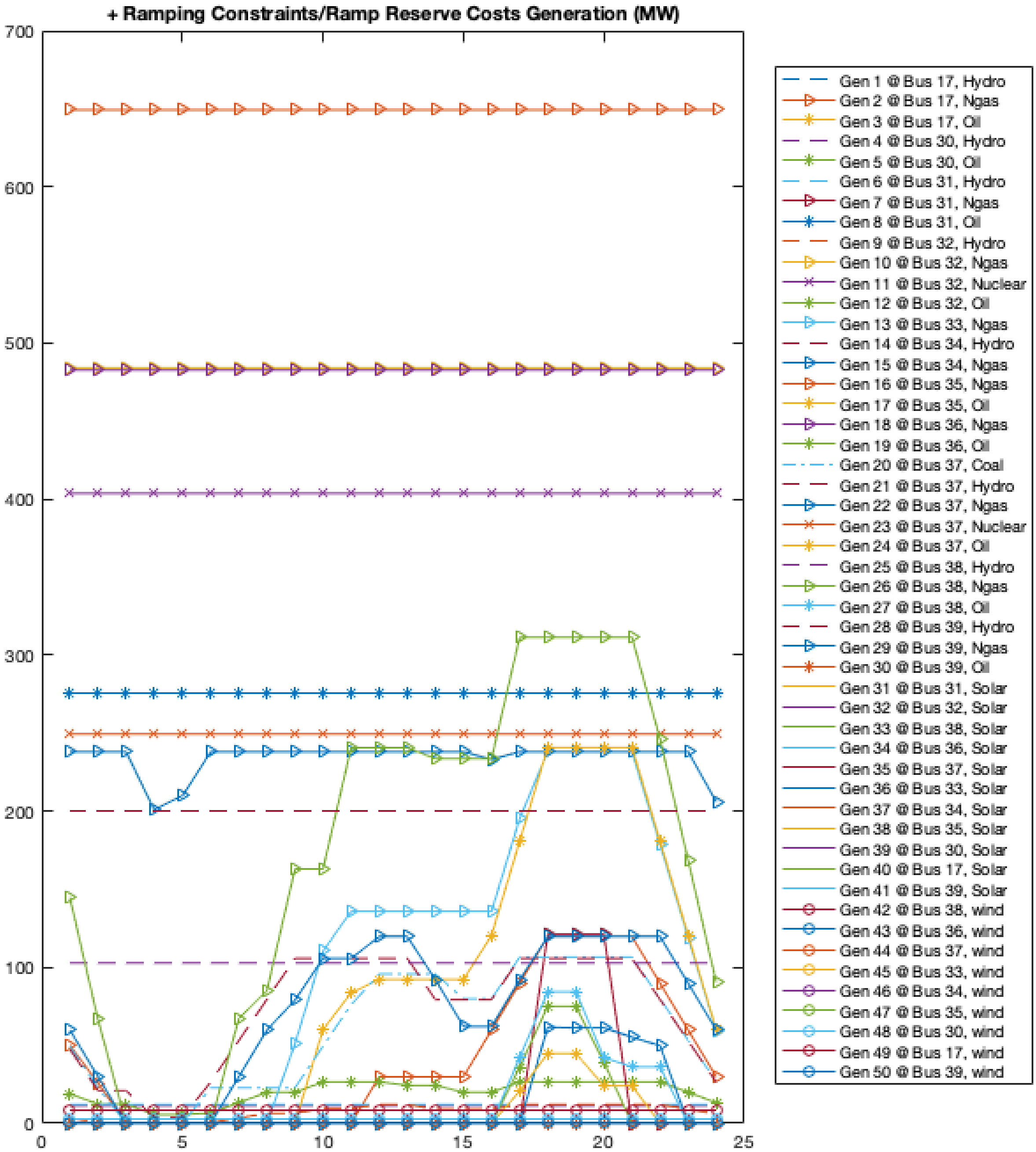


Figure 8: Output of plot_generation function

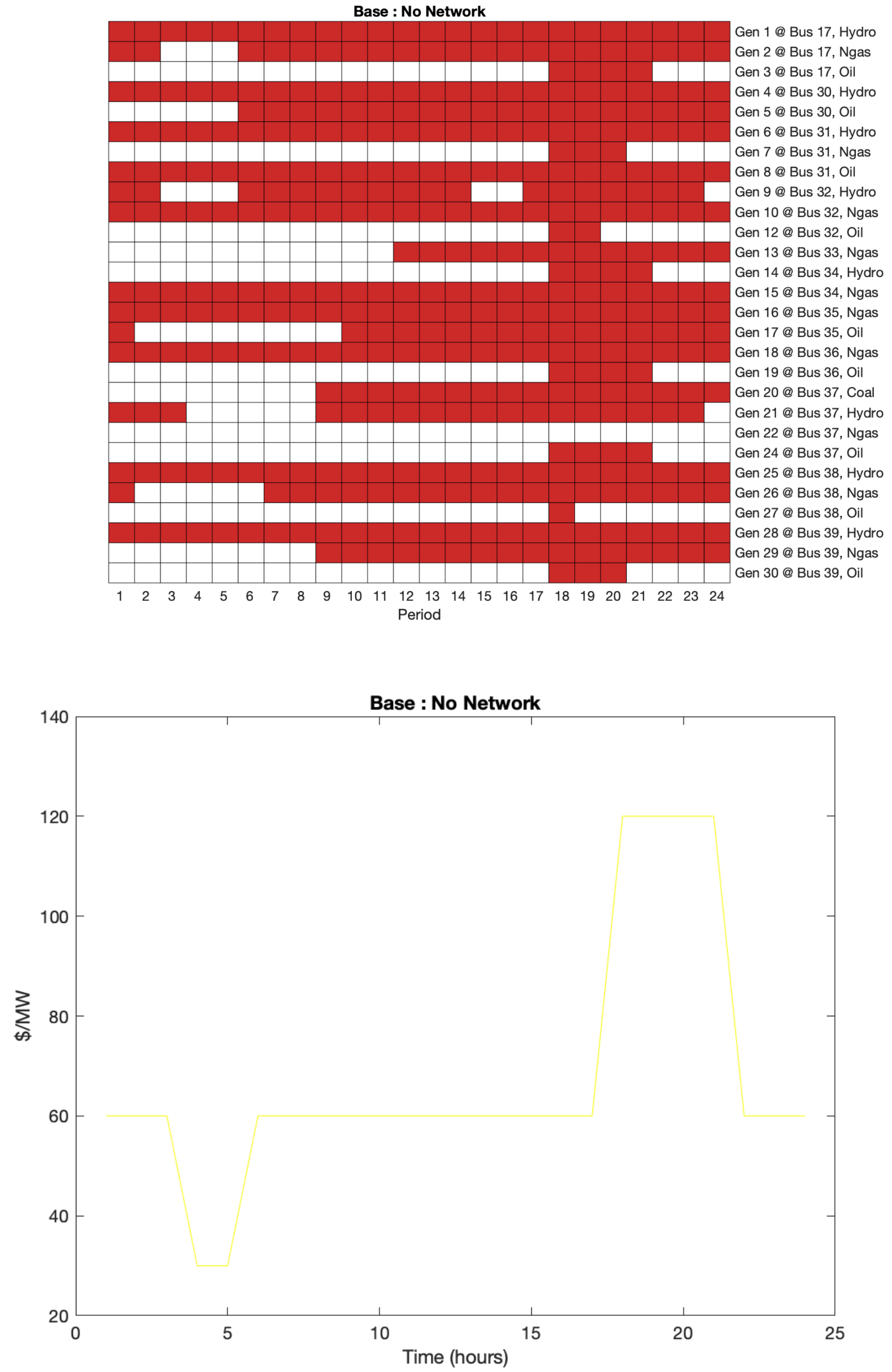
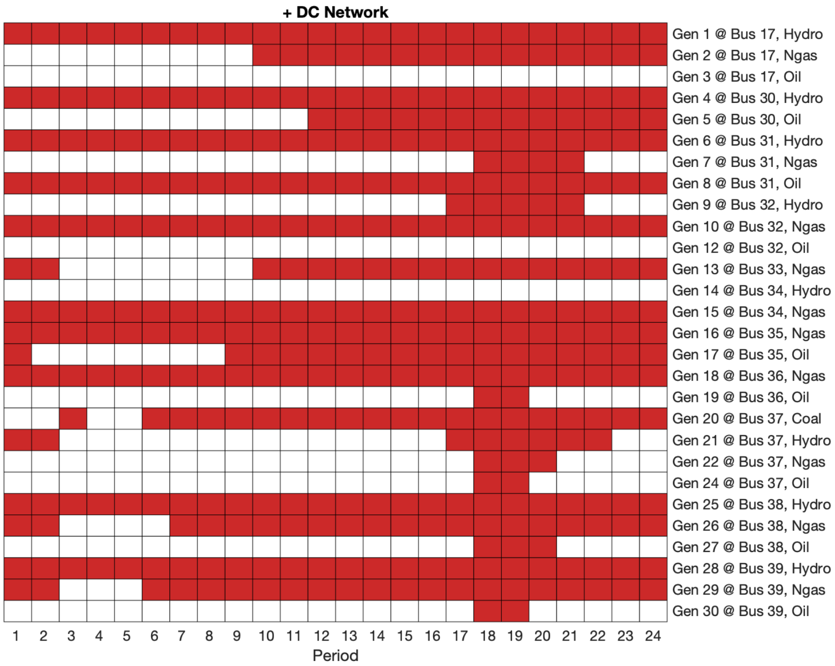


Figure 9: Economic Dispatch



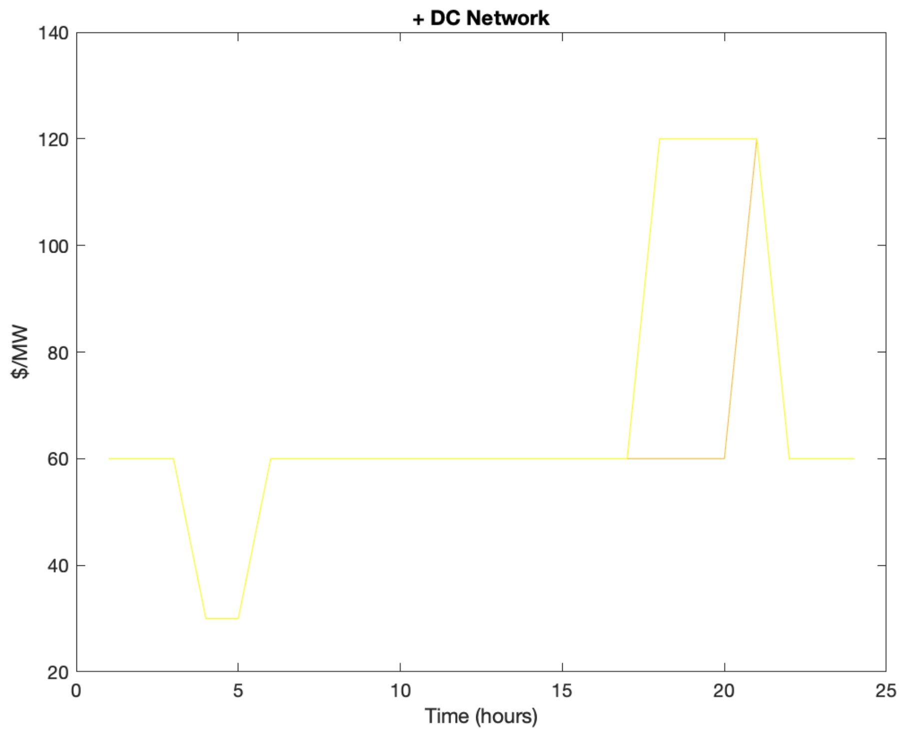


Figure 10: + DC Network

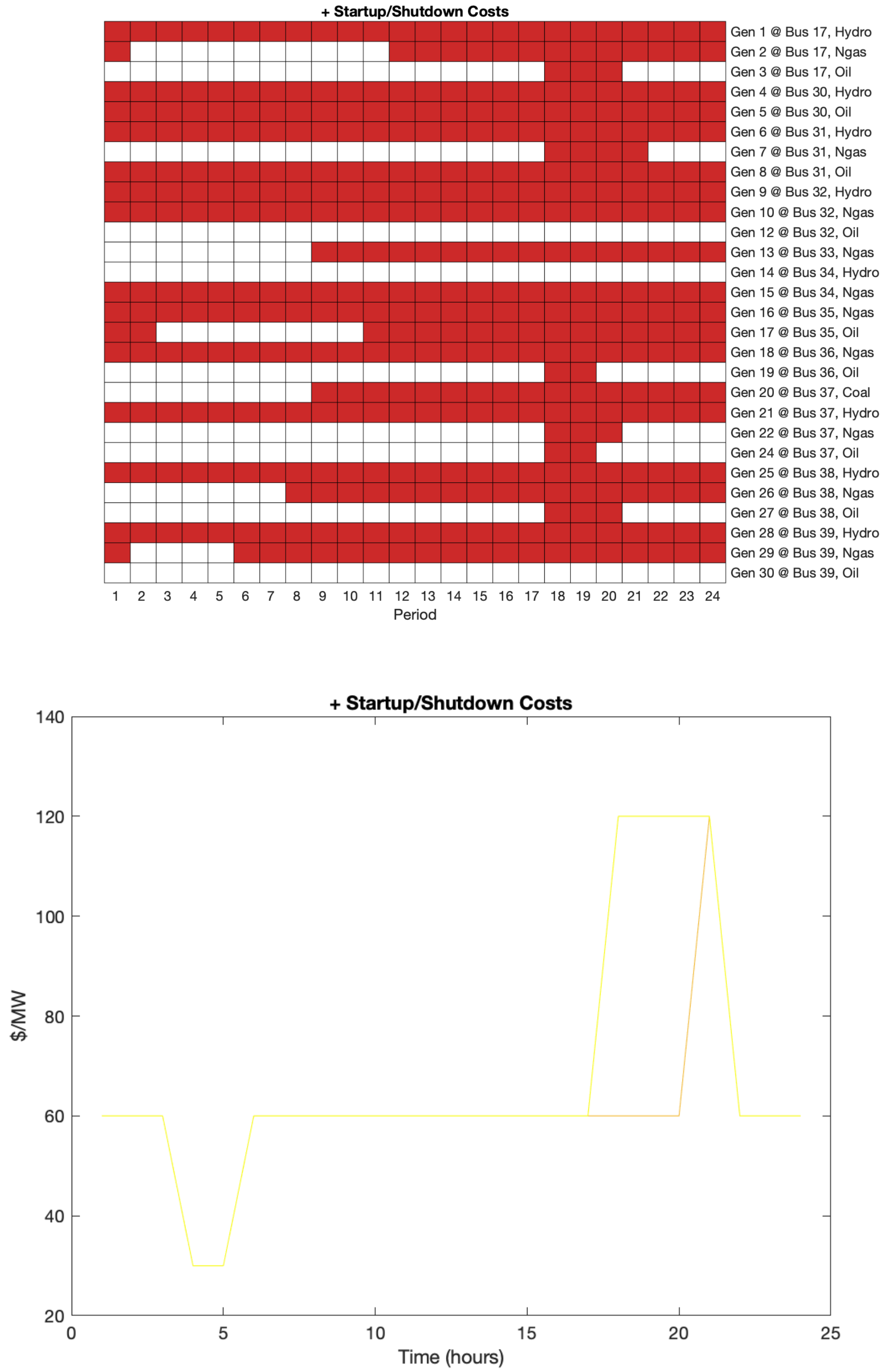


Figure 11: + Startup/Shutdown Costs

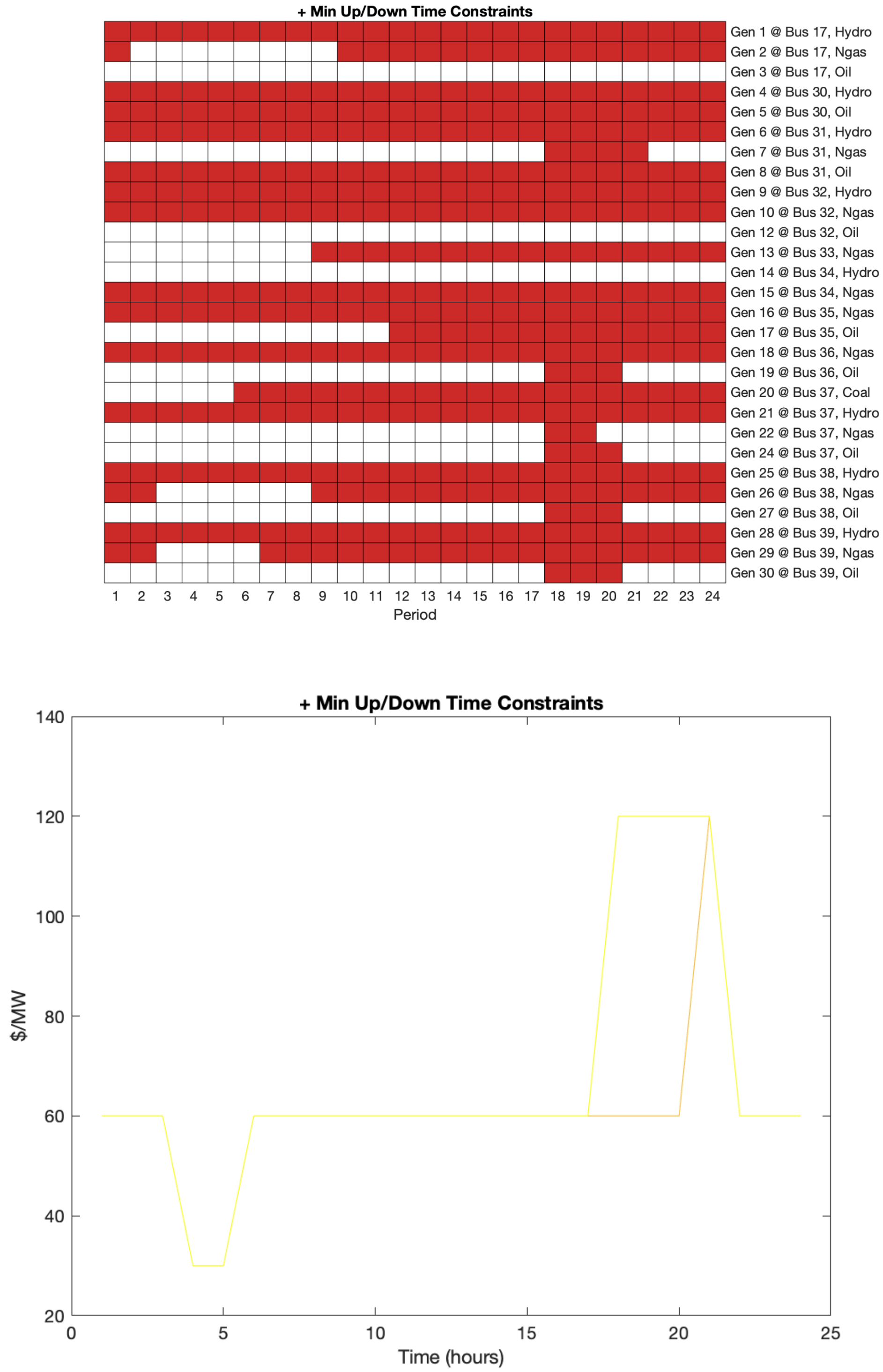
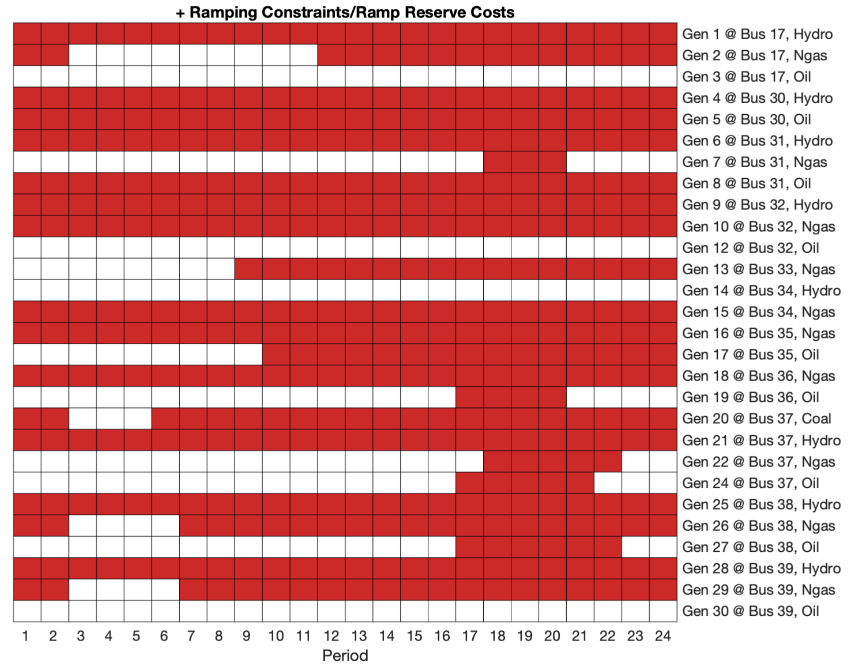


Figure 12: + Minimum Up/Minimum Down Time



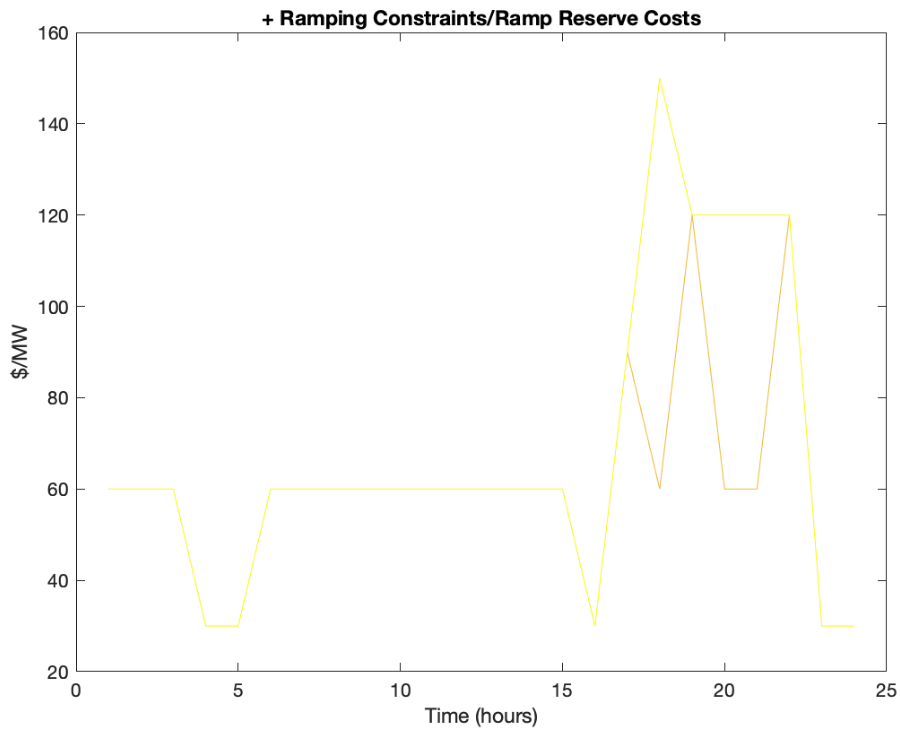


Figure 13: + Ramping

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