OPERATING A POWER GRID IN A PANDEMIC:

Utilizing simulations to recommend practices for a more reliable, cost effective grid.

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Purpose of Report

This report gives recommendations on how to operate a power grid in a pandemic setting. Using a simulation run in MATLAB, we have given recommendations on how to run certain features of a power grid in order to maintain reliability and cost effectiveness of the grid. In the table found in the “Key Recommendations” section of the report you can find the recommendations we have made for crew allocations, security constraints, load shedding, and lines flows. At the end of this report in the “Contagiousness” section we test these recommendations against a more contagious pandemic. In the simulation we used, each “turn” is a 8 hour time period of either morning, evening, or nighttime; therefore, our recommendations are based off of 8 hour time periods. Detailed explanations of these recommendations can also be found further in the report under “Experimentation and Analysis”.

Key Recommendations:

Parameter	Recommendation
Crew Allocations: Maintenance	● We recommend sending out crew to do maintenance on any lines at or above 0.02 probability factor of failure. ● We recommend that no more than 4 crews be sent out in an 8 hour time period. ● We recommend when there is a failed line that no more than 2 crews be sent out for maintenance. ● We recommend that if there are only 3 crews left, no crews be sent out for maintenance.
Crew Allocations: Repair	● We recommend sending three crews to a failed line. ● We recommend that if there are only three crews remain to only send one crew per 8 hour period on all further failures.
Security Constraints	● We recommend using N-1 contingencies.
Load Shedding	● We recommend shedding 50% of the load shed value.
Line Flows	● We recommend not adjusting line flows.

Impacts of Pandemics on Power Grids:

Pandemics impact every facet of life, whether people travel, how they interact with others, where they conduct their work, how often they leave their homes, and how much power they consume. The transition of working in an office to working from home shifts loads away from commercial buildings to residential areas. Neighborhoods that may have demanded little load during the day as residents were at school or at work, greatly feel the impact as students and employees begin working from home (Hsu). Another important aspect of the effect of a pandemic on a power grid is how it affects those working on line repair and maintenance. With a communicable disease, entire crews can fall ill or require quarantine which depletes that resource at faster rates than previously seen. Knowing which lines to prioritize when it comes to maintenance and repair becomes even more critical.

COVID-19 has given some insight on how a pandemic can cause power consumption changes in ways previously never seen before. One strong example of this was in New York City (Hsu). The night time lights of the city dimmed by 40 percent between February and April of 2020. The Northeastern region of the United States saw some of the most extreme changes in power consumption. In the South, utility companies like Georgia Power temporarily suspended customer disconnect services, and implemented restrictions regarding in-person business (Georgia Power).

Rapidly changing conditions and recommended precautions during a pandemic, cause energy services to change how they provide reliable power to customers while maintaining safety for employees and consumers alike.

The Pandemic Simulation Model:

The recommendations in this report are based on tests done on a simulation of a hypothetical Georgia power system during a pandemic. The purpose of this simulation is to operate, maintain, and repair the power grid. We must balance the need to maintain low-cost and reliable power system operations against the health risk imposed on the repair and maintenance crews. The system has 20 buses, 6 generators, and 30 transmission lines, which will behave fairly typical to a normal grid with load demands proportional to the actual load demands. At the start of the simulation, you can see a grid similar to **Figure 1**.

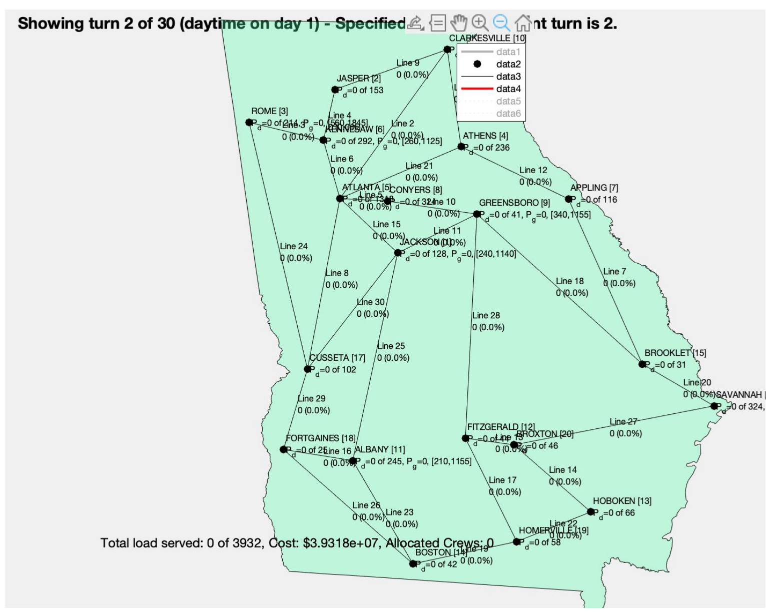


Figure 1. Image of fictitious grid of Georgia.

The simulation runs a DC power flow approximation which means only active power and voltage angles are considered in the formulation. Each time period (night, day, and evening) has different load demands with the evening periods having the highest load demands and the night period having the lowest. The simulation starts on a Monday of the first week of January with 52 weeks ending on the last week in December. To progress through the simulation you take your “next turn” as shown in **Figure 2**.

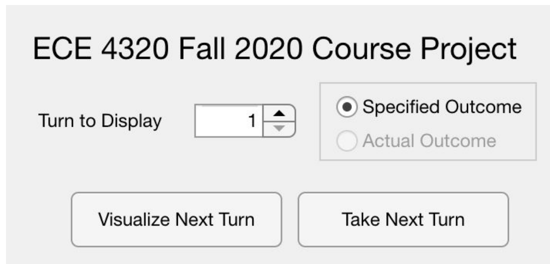


Figure 2. Image of how to take a next turn in the simulation.

When a turn is taken, the simulation prints out a system summary, branch data, bus data, generation constraints, generation cost, load shed penalty, and total system cost.

This simulation allows you to adjust many of its parameters, including the number of turns in a simulation, number of crews available for allocation, etc. In **Figure 3**, these are the parameters the recommendations in this report are based off of.

```
% Simulation parameters
lastTurn = 30; % Number of time periods
ncrew = 10; % Initial number of repair and maintenance crews

% Load demand parameters
opts.Psigma = 0.2; % Standard deviation of the random term driving the load demand variation
opts.Pmu = 1.5; % Multiplicative offset for the random term driving the load demand variation
opts.TimesOfDay = [1 1 6].'; % These entries correspond to midnight, 9:00 am, and 6:00 pm
opts.StartWeek = 40; % Start on the 40th week of the year (in the fall)

% Line failure probability parameters
opts.minFailureProbability = 0.0008; % Minimum achievable failure probability
opts.failProb = 0.02; % Starting maximum failure probability (for non-outliers)
opts.outlierFailProb = 0.08; % Failure probability for a small number of outlier lines
opts.outlierFraction = 0.05; % Fraction of outlier lines with large failure probabilities
opts.FailureRateIncrease = 1.01; % Increase the failure probabilities by this factor every time period
opts.instaFail = 1.20; % Factor of line over loading for which the line fails with 100% probability
opts.cascadeFailureStatus = 0.67; % Status for lines which fail due to line overload

% Tolerance for comparing power generation and load quantities throughout the code
opts.Ptol = 0.1; % MW

% Crew parameters
opts.crewQuarantinePenalty = 0.1; % Penalty factor for quarantined crews in the final score
opts.proximitySicknessLikelihood = 0.05; % Increased likelihood of getting sick for every crew at a location
opts.repairEffectiveness = 0.34; % Fraction of a line that can be repaired each turn
opts.maintenanceEffectiveness = 0.4; % Maintenance performed by a single crew each turn (fraction of line failure
```

Figure 3. Image of what the set parameters are for the simulation

At the start of the simulation all lines are in-service and no crew is quarantined. As the simulation goes on, we have to make decisions regarding allocating crews and maintaining/repairing the line, shedding load, adjusting line flows, changing security constraints, etc. Lines may fail due to natural disasters or by the power flow being greater than line flow limits. A line's chance of failure can be lowered by allocating crews to the line. If a line fails, crews can be allocated to fix the line. Failed lines can cause cascading failures on other lines in the system. Allocating a crew can cause a crew to be quarantined. If a crew is quarantined at any point in the simulation, that crew can no longer be allocated.

Security constraints are used to minimize the generation cost as well as remaining secure against contingency scenarios. The simulation looks at the generator setpoints and also the load demands to see all the different contingency scenarios and figure out how much load it must shed to protect the grid. How secure the system and how much load is shed depends on which security constraint used (N-1, N-k).

Scoring is based on the summation of the load shedding and generation costs over the time period and then multiplied by a penalty due to all the crews that had to get quarantined.

This simulation is robust so it can be used to test various scenarios. In our report, we selected what we believed to be the most important parameters to change, however there are many possible cases to test using this simulation.

Selected Parameters:

Crews Allocations: Maintenance and Repair : This parameter was selected because it is extremely important to be maintaining and repairing lines in the power grid. If you do not maintain lines their likelihood of failure increases, and once a line fails it causes power outages for customers. It is important to optimize this area due to the fact that there are limited crews available and a pandemic adds the possibility for crews to be quarantined and no longer available.

Security Constraints (N-1 vs N-2 contingencies): This parameter was chosen because it provides information on the generators and load demands that could minimize the generation cost as well as remaining secure against contingency scenarios. Figuring out how secure we need to run the grid is important when maintaining the line operational especially during a pandemic.

Load Shedding: This parameter was chosen because load shedding happens when there is not enough electricity available to meet the demands of all customers so energy supply will be interrupted in certain areas. This is used as a last resort to balance the supply and demand and prevent the entire grid from experiencing a permanent blackout. It is important to optimize this parameter to maintain grid integrity without a dramatic increase in price.

Line Flows: This parameter was selected because failed lines can cause cascading failures by overloading other lines in the system. Optimizing this parameter would prevent the loss of power due to failures from other areas in the system, and would allow customers more reliable energy.

Level of Contagiousness: This parameter was selected because we believe it is important to test our recommendations in changing pandemic conditions. We want to know if a pandemic occurred with a higher rate of contagiousness, how well our recommendations would hold up.

Experimentation and Analysis:

Crews Allocations: Maintenance

To make a recommendation on how to allocate crews for maintenance, there are a few important factors to consider. These include the range of failure probabilities usually seen in any given simulation run, frequency of failure in certain probability ranges, and probability of a crew being quarantined.

First, we found the average range of probabilities for a line failing is between approximately 0.004-0.09. We then looked at how long it would take a line to fail without any maintenance, to determine how to prioritize crews. While all lines have given probabilities so it is known which ones have a higher chance of failure than others, there are not enough crews to send out to every line and sending out all crews is unsafe in a pandemic scenario. Going through the full 30 turns of the simulation, lines that would fail usually had a probability failure above 0.01. While it is always possible for lines with a probability failure below 0.01 to fail, it was seen at a much lower frequency. Lines with a probability over 0.02 almost always failed at some point within the 30 turns of the simulation.

Figure 4 shows the average breakdown of probabilities at the start of a simulation.

11.0000	0.0737
19.0000	0.0733
24.0000	0.0202
18.0000	0.0194
27.0000	0.0188
28.0000	0.0177
25.0000	0.0169
2.0000	0.0155
26.0000	0.0149
7.0000	0.0147
8.0000	0.0137
30.0000	0.0124
21.0000	0.0122
9.0000	0.0112
12.0000	0.0110
23.0000	0.0098
17.0000	0.0094
14.0000	0.0088
10.0000	0.0085
1.0000	0.0078
20.0000	0.0074
3.0000	0.0072
22.0000	0.0072
15.0000	0.0069
29.0000	0.0067
16.0000	0.0065
6.0000	0.0049
13.0000	0.0045
5.0000	0.0045
4.0000	0.0041

Figure 4. Breakdown of transmission lines and their failure probability

The number in the left column represents the line number and the number in the right column represents the line's probability of failure. Each start of the simulation has approximately 3 lines with a probability value of over or equal to 0.02, 12-15 lines with a probability value of over or equal to 0.01, and the rest being below 0.01. The probability of a crew being quarantined is 0.05.

Recommendation:

We recommend sending out crews to do maintenance on any lines at or above 0.02 probability factor. For this grid this should mean that approximately 3-4 crews are being sent out for maintenance. We believe this is a safe number given the probability of a crew being quarantined and the number of crews there are available to allocate. As time progresses, unmaintained lines can have an increase in failure probability and maintained lines will experience a decrease in failure probability. This can cause a shift in the amount of lines in the 0.02 threshold. Because of this, we recommend that no more than 4 crews are being sent out for maintenance in an 8 hour time period. Once the system begins experiencing failures and crews are sent out to fix them, no more than 2 crews should be sent out for maintenance in an 8 hour time period. When the number of remaining crews drops to 3, the remaining crews should only be used for fixing line failures.

Crews Allocations: Repair

To make a recommendation on how to allocate crews for repair, there are a few important factors to consider. These include how long it takes a line to be repaired, speed at which you can repair a line, and probability a crew is quarantined.

First we found that it takes 3 crews to repair a line. This can be the same crew in three different time periods, three different crews on three different days, or three crews on the same day. Each crew that repairs a failed line restores that line 34%. We found that if you send three crews to a failed line you can fix it in one turn. However, if there is an outbreak at that line, all three crews will be quarantined. If you only send one crew per turn, only one crew will be quarantined, but it will take longer to restore power and there is the potential for cascading failures.

Recommendation:

We recommend sending three crews to a failed line. This is because power will be restored quicker and due to the lower infection rate of the disease, through several test runs we found it was very rare for the three crews to be quarantined at once. Due to this, we believe it is a justified tradeoff. However, if you do experience three crews quarantined at once, or if you only have 3 crews left, we recommend to only send one crew per 8 hour period on all further failures.

Security Constraints (N-1 vs N-2 contingencies):

To make a recommendation on what the security constraint contingencies should be, there are a few important factors to consider. These include how conservative the grid wants to run, generation and load demands, and minimizing generation cost.

To start, we looked at some different options for conservativeness: no contingencies, N-1 contingencies, and N-2 contingencies. Having no contingencies in the systems was very unreliable as lines were failing at a high rate. N-1 security considers the individual failures of each line while N-2 security consists of the individual failures for each pair of lines. We tested both the N-1 and N-2 security in several different simulation runs and found that on average N-2 security is more expensive and had a higher load shed. To test N-1 security we ran the code found in **Figure 5** in each turn of the simulation and to test N-2 security we ran the code found in **Figure 6** in each turn of the simulation. For both cases if a line were to have failed and we were to run the security constraint, it would recommend load shedding values and print out generator outputs.

```
% N-1 contingencies
nbranch = size(mpcs{1}.branch,1);
contingencies = eye(nbranch,nbranch);
[sol] = rundcscuc(mps{currentTurn}, contingencies);
```

Figure 5. N-1 Security Contingencies code for each turn of the simulation.

```
%N-2 contingencies
nbranch = size(mpcs{1}.branch,1);
branch_pairs = nchoosek(1:nbranch,2);
contingencies = zeros(nbranch,size(branch_pairs,1));
contingencies(sub2ind(size(contingencies),branch_pairs(:,1),(1:size(branch_pairs,1)).')) = 1;
contingencies(sub2ind(size(contingencies),branch_pairs(:,2),(1:size(branch_pairs,1)).')) = 1;
contingencies = [eye(nbranch,nbranch) contingencies];
[sol] = rundcscuc(mps{currentTurn}, contingencies);
```

Figure 6. N-2 Security Contingencies code for each turn of the simulation.

Recommendations:

We recommend to run N-1 contingencies for the security constraints per 8 hour period (morning, evening, and nighttime). We believe this will hold the integrity of the line with minimal line failures, less load shed, and a lower cost. Even though N-2 was more secure, the cost and the higher amounts of load shed outweigh the benefit.

Load Shedding:

To make a recommendation on how much load the system should shed, there are a few important factors to consider. These include the security constraint to be used and determining what percentage of the load that is recommended to be shed will actually be shed.

We tried two different approaches in the load shed problem. The first was after the security constraint was run, allowing the simulation to handle the load. This would result in shedding 100% of the recommended load shedding value. This usually led to high total load shedding and a higher price for the overall simulation. The second approach was to remove 50% of the load shed value after the security constraint was run. **Figure 7** shows how load shedding was implemented in the simulation and the subsequent values. Load shedding was done in every turn of the simulation. This would allow us to lower the overall cost and the total load shedding.

```
>> sortrows([(1:20).' mpcs{currentTurn}.bus(:,PD)-sol.bus(:,PD)],2,'descend')

ans =

   20.0000   36.8000
   13.0000    8.2000
    2.0000    0.0000
    7.0000    0.0000
    1.0000    0.0000
    3.0000         0
    4.0000         0
    6.0000         0
    8.0000         0
    9.0000         0
   10.0000         0
   11.0000         0
   12.0000         0
   14.0000         0
   15.0000         0
   16.0000         0
   18.0000         0
   17.0000   -0.0000
   19.0000   -0.0000
    5.0000   -0.0000

>> mpcs{currentTurn}.bus(20,PD)=mpcs{currentTurn}.bus(20,PD)*.5;
>> sortrows([(1:20).' mpcs{currentTurn}.bus(:,PD)-sol.bus(:,PD)],2,'descend')

ans =

   20.0000   18.4000
   13.0000    8.2000
    2.0000    0.0000
    7.0000    0.0000
    1.0000    0.0000
    3.0000         0
    4.0000         0
    6.0000         0
    8.0000         0
    9.0000         0
   10.0000         0
   11.0000         0
   12.0000         0
   14.0000         0
   15.0000         0
   16.0000         0
   18.0000         0
   17.0000   -0.0000
   19.0000   -0.0000
    5.0000   -0.0000
```

Figure 7. Code that sheds load by 50%

Recommendations:

We recommend to shed the load value by 50% over the 100% done by the simulation. On average we saw that with an N-1 security contingency the average line outages were 0.4 per 8 hour time period when we shed 50% of the load value but were 0.8 per 8 hour time period when we shed 100% of the load value. We also saw that the price, on average, was cheaper when only 50% shedding was done.

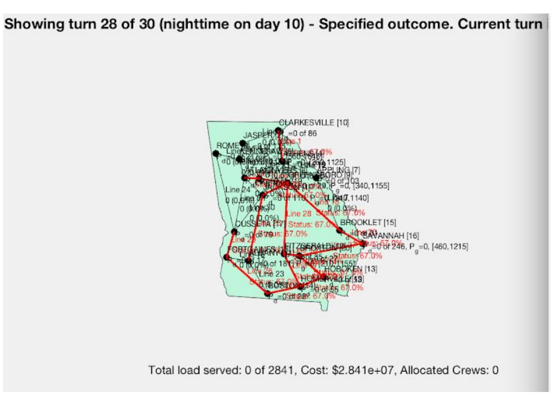
Line Flows:

To make a recommendation on line flows, there are a few important factors to consider. These include their failure probability and their flow rates.

We looked at three different approaches when trying to solve the line flows recommendation. The first was to increase the line flow value by 10%. The code shown in **Figure 8** was executed during every turn. This showed a lower generation cost but had a higher probability of causing cascading failures as shown in **Figure 9**. The second approach was to decrease the line flow value by 10%. The code shown in **Figure 10** was executed during every turn. This showed a greater generation cost and was more expensive due to load shed. Yet this approach, compared to the first approach did have on average a lower amount of failures. The last approach was to leave the system how it was. This by far was the cheapest and on average had a lower amount of faults.

```
%Power Flow 1.1
mpcs{currentTurn}.branch(:,6)=mpcs{currentTurn}.branch(:,6)*1.1;
```

Figure 8. Line Flow increased by 10% during each turn.




```
Line failures:
Line     F_BUS   T_BUS
10               8               9
Line failures due to cascade:
Round   Line     F_BUS   T_BUS
1:               1               10              4
1:               28              9               12
2:               11              1               9
3:               5               5               8
3:               13              20              12
3:               14              20              13
3:               17              12              19
3:               18              9               15
3:               19              14              19
3:               20              16              15
3:               22              19              13
3:               26              14              18
3:               27              20              16
3:               29              17              18
4:               25              1               11
```

Figure 9. Cascade Failure due to increase in line flow by 10%.

```
%Power Flow 0.9
mpcs{currentTurn}.branch(:,6)=mpcs{currentTurn}.branch(:,6)*0.9;
```

Figure 10. Line Flow decreased by 10% during each turn.

Recommendations:

We recommend not adjusting line flow in conjunction with our other recommendations. This will give you a more secure, less expensive grid. If you increase or decrease the line flow by 10% you risk either cascading failures or higher load shedding values.

Contagiousness

After creating our previous recommendations, we increased the contagiousness of our pandemic virus from 5% to 25%. We chose to alter this parameter because every pandemic can have a different rate of contagiousness than the last. These tests were done to see how helpful our recommendations are if the pandemic is more contagious than we expected.

First trial:

In the first trial, all 10 crews were quarantined by turn 21 and could no longer be used for maintenance or repair for the rest of the simulation. Between turns 21-30 two lines failed. In **Figure 11** you can find values for generation cost, load shed penalty, average line outages, and final score.

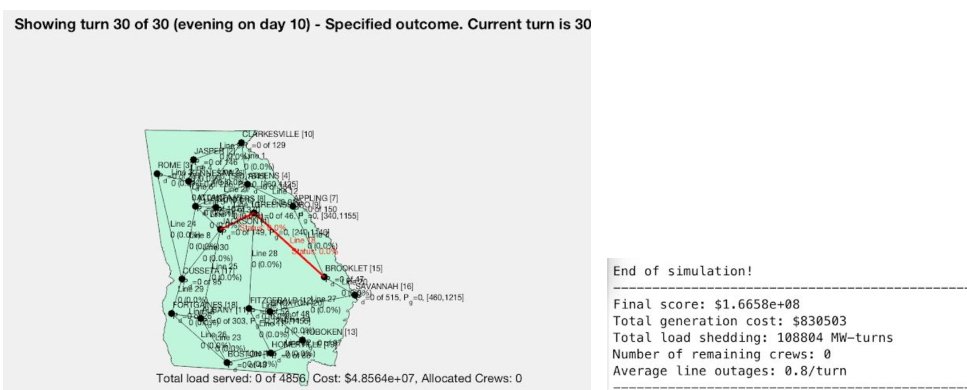


Figure 11. Increased contagiousness trial 1 outcome.

Second Trial:

In the second trial, all 10 crews were quarantined by turn 20 and could no longer be used for maintenance or repair for the rest of the simulation. Between turns 20-30 five more lines failed. In **Figure 12** you can find values for generation cost, load shed penalty, average line outages, and final score.

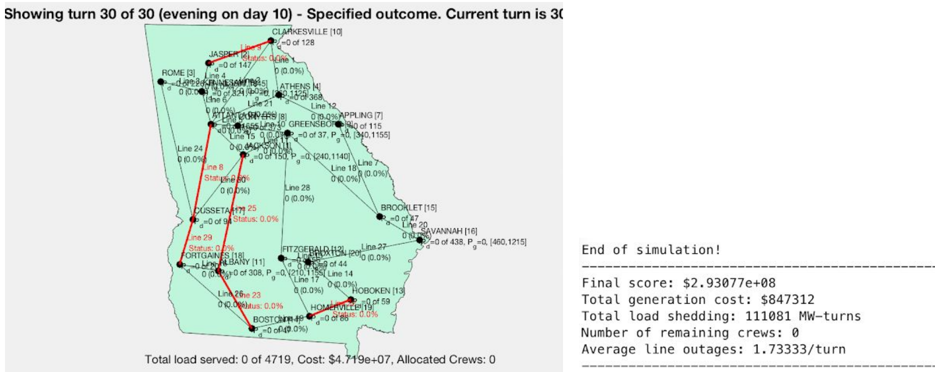


Figure 12. Increased contagiousness trial 2 outcome.

Third Trial:

In the final trial, two crews remained at the end of the simulation. Within the last two turns of the simulation one line failed, since we were being conservative with the amount of crews we deployed to repair lines we only sent one per turn to minimize exposure. On the last turn, another line failed. If there were still turns left, one crew would have been allocated to each of the failed lines. In **Figure 13** you can find values for generation cost, load shed penalty, average line outages, and final score.

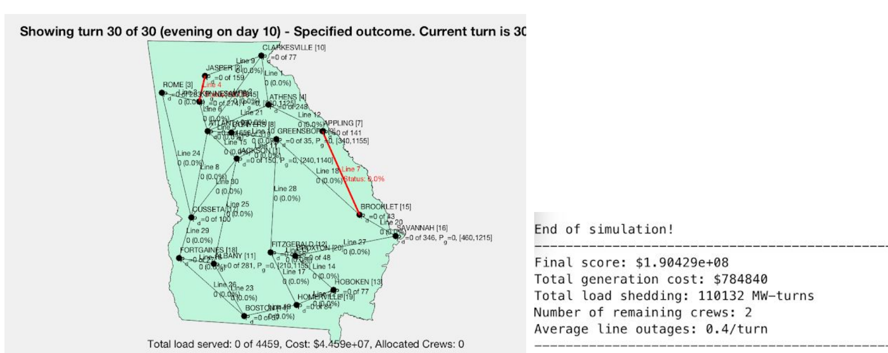


Figure 13. Increased contagiousness trial 3 outcome.

Feedback:

Based on the results of these three trials we believe our recommendations are still beneficial in a more contagious pandemic. However, when the contagion level reaches around 25% as we tested in these trials, we recommend either a more conservative approach to sending out crews, or increasinging the number of available crews to be in the 15-20 crew range. If the number of crews is kept at 10, they will be able to do maintenance and repairs on less lines, less frequently, therefore we recommend a more conservative approach to security constraints and a shift from our original recommendation of N-1 contingencies to N-2.

Conclusion:

Through tests done on the simulation we believe we are able to provide reasonable recommendations on running a power grid safely, reliably, and financially conservative during a pandemic. We recommend sending out crews to do maintenance on any lines at or above 0.02 probability factor of failure except if there are only 3 crews left. If there are only 3 crews left, no crews shall be sent out for maintenance but only to repair failed lines. Additionally, the grid should use a security constraint of N-1 contingencies with 50% load shedding at applicable busses and no adjustments to the line flows. With these recommendations, there are limitations to their scope so we have future plans to improve these recommendations to fulfil the needs of varying pandemic and grid situations.

Limitations:

Due to the differing nature of pandemics as well as areas unable to be tested within the simulation. There are limitations to the recommendations given in this report. The recommendations in this report are based off of a pandemic with a contagious probability of 5%. While we also did testing of a pandemic at 25%, this report contains no recommendations for any pandemic with a probability of contagion over 25%. This simulation also conducted tests across 3 time periods of the day and because there is no way in the simulation to test one time period at a time, it was difficult to make recommendations for a given time period.

Future Implementations:

In the future we will be testing recommendations in isolated time periods to be able to give more specific recommendations on how to operate the grid best in morning, nighttime and evening. Testing in the evening would be beneficial to see how recommendations hold up when demand is highest and allow for the adjusting of some recommendations when load is lower. We will also be continuing to test varying levels of contagiousness to try and cover recommendations for a wider variety of pandemics. We will also try testing a wider range of load sheddings values. In the future we would also like to optimize the number of crews we are using to be able to keep the grid running even if crews are quarantined.

Bibliography

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Hsu, Jeremy. "How the Pandemic Impacts U.S. Electricity Usage." *IEEE Spectrum*, 18 June 2020, https://spectrum.ieee.org/energywise/energy/the-smarter-grid/how-the-pandemic-impacts-us-electricity-usage.

Appendix

Contagiousness Recommendation Example Code

This shows the code we used to test an increase in contagiousness, specifically the first turn with load shedding.

```
% Start the simulation with the GUI
>> ece4320
% Define constants to help reference qualities in the Matpower format
>> define_constants
% Getting parameter values that initialize the Security Constraint
>> nbranch = size(mpcs{1}.branch,1);
% Display the lines with the highest failure probability
>> sortrows([(1:30).' mpcs{currentTurn}.failure_probability],2,'descend')

ans =
   18.0000    0.0200
   27.0000    0.0193
    3.0000    0.0186
   28.0000    0.0182
   25.0000    0.0174
    2.0000    0.0160
   26.0000    0.0154
    7.0000    0.0151
    8.0000    0.0142
    9.0000    0.0136
   30.0000    0.0128
   21.0000    0.0125
   24.0000    0.0125
   12.0000    0.0113
   23.0000    0.0101
   19.0000    0.0100
   17.0000    0.0097
   14.0000    0.0091
   10.0000    0.0088
   11.0000    0.0083
    1.0000    0.0080
   20.0000    0.0076
   22.0000    0.0074
   15.0000    0.0071
   29.0000    0.0069
   16.0000    0.0067
    6.0000    0.0050
   13.0000    0.0047
    5.0000    0.0046
    4.0000    0.0043
% Allocating crews to the failed lines (line 2 and line 28) and lines with a
% failure probability greater than or equal to 0.02 (line 18)
>> crewAllocation(1) = 2;
>> crewAllocation(2) = 28;
>> crewAllocation(3) = 18;
```

```
% Running an N-1 security-constrained unit commitment to determine generator
% outputs and any load shedding
>> contingencies = eye(nbranch,nbranch);
>> [sol] = rundcscuc(mpcs{currentTurn}, contingencies);
>> printpf(sol)

Converged in 0.00 seconds
Objective Function Value = 239545.64 $/hr
================================================================================
=|System Summary
|===============================================================================
==

How many?                How much?              P (MW)            Q (MVAr)
---------------------    -------------------  -------------  -----------------
Buses                20    Total Gen Capacity    7635.0           0.0 to 0.0
Generators            6    On-line Capacity      7635.0           0.0 to 0.0
Committed Gens        6    Generation (actual)   3063.6              0.0
Loads                20    Load                  3063.6              0.0
  Fixed              20      Fixed               3063.6              0.0
  Dispatchable        0      Dispatchable          -0.0 of -0.0     -0.0
Shunts                0    Shunt (inj)             -0.0              0.0
Branches             30    Losses (I^2 * Z)         0.00             0.00
Transformers          0    Branch Charging (inj)     -               0.0
Inter-ties            0    Total Inter-tie Flow     0.0              0.0
Areas                 1

                          Minimum                      Maximum
                 -------------------------  --------------------------------
Voltage Magnitude   1.000 p.u. @ bus 1          1.000 p.u. @ bus 1
Voltage Angle      -9.82 deg   @ bus 10        20.99 deg   @ bus 11
Lambda P            0.00 $/MWh @ bus 1          0.00 $/MWh @ bus 1
Lambda Q            0.00 $/MWh @ bus 1          0.00 $/MWh @ bus 1

================================================================================
=|Bus Data
|===============================================================================
==
 Bus      Voltage          Generation             Load
Lambda($/MVA-hr)
  #   Mag(pu) Ang(deg)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)     P        Q
----- ------- --------  --------  --------  --------  --------  -------
-------
    1  1.000   13.421    560.65      0.00    127.60      0.00    0.000     -
    2  1.000   -6.545       -          -      74.50      0.00    0.000     -
    3  1.000   -1.082      0.00      0.00    182.10      0.00    0.000     -
    4  1.000   -9.391       -          -     207.30      0.00    0.000     -
    5  1.000   -8.683       -          -    1203.00      0.00    0.000     -
    6  1.000    0.000*   802.48      0.00    159.10      0.00    0.000     -
    7  1.000   -6.397       -          -      71.20      0.00    0.000     -
    8  1.000   -2.092       -          -     191.30      0.00    0.000     -
    9  1.000   17.527    617.22      0.00     29.90      0.00    0.000     -
   10  1.000   -9.824       -          -      75.50      0.00    0.000     -
   11  1.000   20.995    623.25      0.00    166.60      0.00    0.000     -
   12  1.000    7.073       -          -      38.20      0.00    0.000     -
   13  1.000    6.139       -          -      55.40      0.00    0.000     -
   14  1.000    9.825       -          -      28.80      0.00    0.000     -
```

15	1.000	8.302	-	-	37.30	0.00	0.000	-
16	1.000	16.123	460.00	0.00	244.30	0.00	0.000	-
17	1.000	4.405	-	-	72.50	0.00	0.000	-
18	1.000	6.818	-	-	19.00	0.00	0.000	-
19	1.000	8.065	-	-	48.30	0.00	0.000	-
20	1.000	9.759	-	-	31.70	0.00	0.000	-
		Total:	3063.60	0.00	3063.60	0.00		

=|Branch Data

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	10	4	-7.68	0.00	7.68	0.00	0.000	0.00
2	5	10	0.00	0.00	0.00	0.00	0.000	0.00
3	3	6	-84.39	0.00	84.39	0.00	0.000	0.00
4	6	2	142.32	0.00	-142.32	0.00	0.000	0.00
5	5	8	-174.21	0.00	174.21	0.00	0.000	0.00
6	6	5	416.67	0.00	-416.67	0.00	0.000	0.00
7	7	15	-245.37	0.00	245.37	0.00	0.000	0.00
8	5	17	-226.05	0.00	226.05	0.00	0.000	0.00
9	10	2	-67.82	0.00	67.82	0.00	0.000	0.00
10	8	9	-365.51	0.00	365.51	0.00	0.000	0.00
11	1	9	-61.26	0.00	61.26	0.00	0.000	0.00
12	7	4	174.17	0.00	-174.17	0.00	0.000	0.00
13	20	12	17.76	0.00	-17.76	0.00	0.000	0.00
14	20	13	44.11	0.00	-44.11	0.00	0.000	0.00
15	1	5	426.88	0.00	-426.88	0.00	0.000	0.00
16	11	18	237.05	0.00	-237.05	0.00	0.000	0.00
17	12	19	-20.44	0.00	20.44	0.00	0.000	0.00
18	9	15	160.55	0.00	-160.55	0.00	0.000	0.00
19	14	19	80.03	0.00	-80.03	0.00	0.000	0.00
20	16	15	122.13	0.00	-122.13	0.00	0.000	0.00
21	4	5	-40.80	0.00	40.80	0.00	0.000	0.00
22	19	13	11.29	0.00	-11.29	0.00	0.000	0.00
23	14	11	-160.77	0.00	160.77	0.00	0.000	0.00
24	17	3	97.71	0.00	-97.71	0.00	0.000	0.00
25	1	11	-58.84	0.00	58.84	0.00	0.000	0.00
26	14	18	51.94	0.00	-51.94	0.00	0.000	0.00
27	20	16	-93.57	0.00	93.57	0.00	0.000	0.00
28	9	12	0.00	0.00	0.00	0.00	0.000	0.00
29	17	18	-269.99	0.00	269.99	0.00	0.000	0.00
30	1	17	126.27	0.00	-126.27	0.00	0.000	0.00
						Total:	0.000	0.00

=|Generation Constraints

Gen #	Bus #	Active Power Limits Pmin mu	Pmin	Pg	Pmax	Pmax mu
2	3	0.000	560.00	-	1845.00	-

```
   6    16      0.000    460.00    460.00   1215.00      -

% Show any load shedding
>> sortrows([(1:20).' mpcs{currentTurn}.bus(:,PD)-sol.bus(:,PD)],2,'descend')

ans =
    2.0000   21.6000
    4.0000    0.0000
   10.0000    0.0000
    7.0000    0.0000
   17.0000    0.0000
   14.0000    0.0000
   18.0000    0.0000
   20.0000    0.0000
    1.0000         0
    3.0000         0
    5.0000         0
    6.0000         0
    8.0000         0
   11.0000         0
   12.0000         0
   13.0000         0
   16.0000         0
   19.0000         0
    9.0000   -0.0000
   15.0000   -0.0000

% Since solution does have load shedding, half the load shed value
>> mpcs{currentTurn}.bus(2,PD)=mpcs{currentTurn}.bus(2,PD)*.5;
% Making sure the load shedding halved
>> sortrows([(1:20).' mpcs{currentTurn}.bus(:,PD)-sol.bus(:,PD)],2,'descend')

ans =
    4.0000    0.0000
   10.0000    0.0000
    7.0000    0.0000
   17.0000    0.0000
   14.0000    0.0000
   18.0000    0.0000
   20.0000    0.0000
    1.0000         0
    3.0000         0
    5.0000         0
    6.0000         0
    8.0000         0
   11.0000         0
   12.0000         0
   13.0000         0
   16.0000         0
   19.0000         0
    9.0000   -0.0000
   15.0000   -0.0000
    2.0000  -26.4500

% Assign the solution from the security-constrained unit commitment to the
% appropriate variables
>> Pg = sol.gen(:,PG);
```

```
>> Pd = sol.bus(:,PD);

% Clicking the Take Next button in the GUI results in the following output.
% This output corresponds to what actually happened on the simulation for this
% turn. You will see the generation cost, and the load shedding cost and
penalties.

Update for Turn 4:

Converged in 0.00 seconds
Objective Function Value = 239545.64 $/hr
================================================================================
=|System Summary
|===============================================================================
==

How many?                How much?              P (MW)            Q (MVAr)
---------------------    -------------------  -------------  -----------------
Buses                20     Total Gen Capacity    7635.0           0.0 to 0.0
Generators            6     On-line Capacity      7635.0           0.0 to 0.0
Committed Gens        6     Generation (actual)   3063.6              0.0
Loads                20     Load                  3063.6              0.0
  Fixed              20       Fixed               3063.6              0.0
  Dispatchable        0       Dispatchable          -0.0 of -0.0     -0.0
Shunts                0     Shunt (inj)             -0.0              0.0
Branches             30     Losses (I^2 * Z)         0.00             0.00
Transformers          0     Branch Charging (inj)     -               0.0
Inter-ties            0     Total Inter-tie Flow     0.0              0.0
Areas                 1

                          Minimum                      Maximum
                 -------------------------  --------------------------------
Voltage Magnitude   1.000 p.u. @ bus 1          1.000 p.u. @ bus 1
Voltage Angle      -9.82 deg   @ bus 10        20.99 deg   @ bus 11
Lambda P            0.00 $/MWh @ bus 1          0.00 $/MWh @ bus 1
Lambda Q            0.00 $/MWh @ bus 1          0.00 $/MWh @ bus 1

================================================================================
=|Bus Data
|===============================================================================
==
 Bus      Voltage          Generation             Load
Lambda($/MVA-hr)
  #   Mag(pu) Ang(deg)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)     P        Q
----- ------- --------  --------  --------  --------  --------  -------
-------
    1  1.000   13.421    560.65      0.00    127.60      0.00    0.000     -
    2  1.000   -6.545      -          -       74.50      0.00    0.000     -
    3  1.000   -1.082      0.00      0.00    182.10      0.00    0.000     -
    4  1.000   -9.391      -          -      207.30      0.00    0.000     -
    5  1.000   -8.683      -          -     1203.00      0.00    0.000     -
    6  1.000    0.000*   802.48      0.00    159.10      0.00    0.000     -
    7  1.000   -6.397      -          -       71.20      0.00    0.000     -
    8  1.000   -2.092      -          -      191.30      0.00    0.000     -
    9  1.000   17.527    617.22      0.00     29.90      0.00    0.000     -
   10  1.000   -9.824      -          -       75.50      0.00    0.000     -
   11  1.000   20.995    623.25      0.00    166.60      0.00    0.000     -
```

```
   12  1.000    7.073        -         -       38.20      0.00     0.000     -
   13  1.000    6.139        -         -       55.40      0.00     0.000     -
   14  1.000    9.825        -         -       28.80      0.00     0.000     -
   15  1.000    8.302        -         -       37.30      0.00     0.000     -
   16  1.000   16.123    460.00      0.00    244.30      0.00     0.000     -
   17  1.000    4.405        -         -       72.50      0.00     0.000     -
   18  1.000    6.818        -         -       19.00      0.00     0.000     -
   19  1.000    8.065        -         -       48.30      0.00     0.000     -
   20  1.000    9.759        -         -       31.70      0.00     0.000     -
                         --------  --------  --------  --------
                Total:   3063.60      0.00   3063.60      0.00

================================================================================
=|Branch Data
|===============================================================================
==
Brnch   From   To    From Bus Injection   To Bus Injection     Loss (I^2 * Z)
  #     Bus    Bus    P (MW)   Q (MVAr)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)
-----  -----  -----  --------  --------  --------  --------  --------  --------
   1     10      4     -7.68      0.00      7.68      0.00     0.000      0.00
   2      5     10      0.00      0.00      0.00      0.00     0.000      0.00
   3      3      6    -84.39      0.00     84.39      0.00     0.000      0.00
   4      6      2    142.32      0.00   -142.32      0.00     0.000      0.00
   5      5      8   -174.21      0.00    174.21      0.00     0.000      0.00
   6      6      5    416.67      0.00   -416.67      0.00     0.000      0.00
   7      7     15   -245.37      0.00    245.37      0.00     0.000      0.00
   8      5     17   -226.05      0.00    226.05      0.00     0.000      0.00
   9     10      2    -67.82      0.00     67.82      0.00     0.000      0.00
  10      8      9   -365.51      0.00    365.51      0.00     0.000      0.00
  11      1      9    -61.26      0.00     61.26      0.00     0.000      0.00
  12      7      4    174.17      0.00   -174.17      0.00     0.000      0.00
  13     20     12     17.76      0.00    -17.76      0.00     0.000      0.00
  14     20     13     44.11      0.00    -44.11      0.00     0.000      0.00
  15      1      5    426.88      0.00   -426.88      0.00     0.000      0.00
  16     11     18    237.05      0.00   -237.05      0.00     0.000      0.00
  17     12     19    -20.44      0.00     20.44      0.00     0.000      0.00
  18      9     15    160.55      0.00   -160.55      0.00     0.000      0.00
  19     14     19     80.03      0.00    -80.03      0.00     0.000      0.00
  20     16     15    122.13      0.00   -122.13      0.00     0.000      0.00
  21      4      5    -40.80      0.00     40.80      0.00     0.000      0.00
  22     19     13     11.29      0.00    -11.29      0.00     0.000      0.00
  23     14     11   -160.77      0.00    160.77      0.00     0.000      0.00
  24     17      3     97.71      0.00    -97.71      0.00     0.000      0.00
  25      1     11    -58.84      0.00     58.84      0.00     0.000      0.00
  26     14     18     51.94      0.00    -51.94      0.00     0.000      0.00
  27     20     16    -93.57      0.00     93.57      0.00     0.000      0.00
  28      9     12      0.00      0.00      0.00      0.00     0.000      0.00
  29     17     18   -269.99      0.00    269.99      0.00     0.000      0.00
  30      1     17    126.27      0.00   -126.27      0.00     0.000      0.00
                                                             --------  --------
                                                    Total:     0.000      0.00

================================================================================
=|Generation Constraints
|===============================================================================
==
 Gen   Bus                 Active Power Limits
```

#	#	Pmin mu	Pmin	Pg	Pmax	Pmax mu
2	3	0.000	560.00	-	1845.00	-
6	16	0.000	460.00	460.00	1215.00	-

Generation cost: $23546
Load shed penalty: $2.16e+05
Total cost: $2.3955e+05

Maintenance: Updated Failure Probability

Line	F_BUS	T_BUS	Previous	New
18	9	15	0.020	0.012

Repair Updates: Line Status

Line	F_BUS	T_BUS	Previous	New
2	5	10	0.000	0.340
28	9	12	0.000	0.340