The George Washington University, Department of Mechanical Engineering

DESIGN AND MODELING OF A STEAM BYPASS SYSTEM IN A CENTRAL UTILITY PLANT

Capstone Design Project

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ABSTRACT

Currently, the small-scale Central Utility Plant (CUP) at The George Washington University is limited by its inability to handle excess steam. This report explores two potential solutions to the issues limiting the utilization of the steam turbine and the efficiency of the power plant. A preliminary analysis of a battery storage system is considered based on available literature and data. Then, a model of the CUP was designed in Simulink using the Thermolib library to simulate the components of the power plant. Each component was verified with manual calculations before using metered data gathered from the plant's automatic control systems to identify component efficiencies and improve accuracy. After adding a steam bypass system, the simulated model proved the utilization rate of the steam turbine would increase. This leads to an increase in the plant's overall efficiency because steam would no longer limit the power output of the gas turbine. While there are further studies to be done towards improving accuracy of the model and determine the specifications of a bypass solution, a dump condenser has been shown to be a feasible solution to manage excess steam, improve efficiency and lead to financial savings.

TEAM MEMBER ROLES

Ryan Welch: Brayton Cycle Modeling, Chief Writer, Evaluation and Conclusions

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Jacob Blumen: Steam Cycle Modeling, steam bypass system modeling, boiler modeling, building heat modeling. Chief Writer, Design Description.

INTRODUCTION

Combined heat and power plants are becoming more common for Universities to provide electricity and steam to buildings on their campuses. At the George Washington University, the Central Utility Plant (CUP) is rated to produce 7.4 MW of power, providing electricity and steam to four nearby buildings. Producing electricity in the CUP, running at capacity, is more efficient than purchasing electricity from the local utility, PEPCO. The CUP is limited by three major issues stemming from weather, and an inability to deal with excess electricity and/or excess steam. These factors have limited utilization of the plant's components which has a major impact on the plant's ability to make the return on investment previously expected from preliminary analysis during the plant's design [1]. This design project evaluates the proposed solution of adding a steam bypass system by first creating a model in MATLAB Simulink and analyzing the difference in utilization, efficiency and cost.

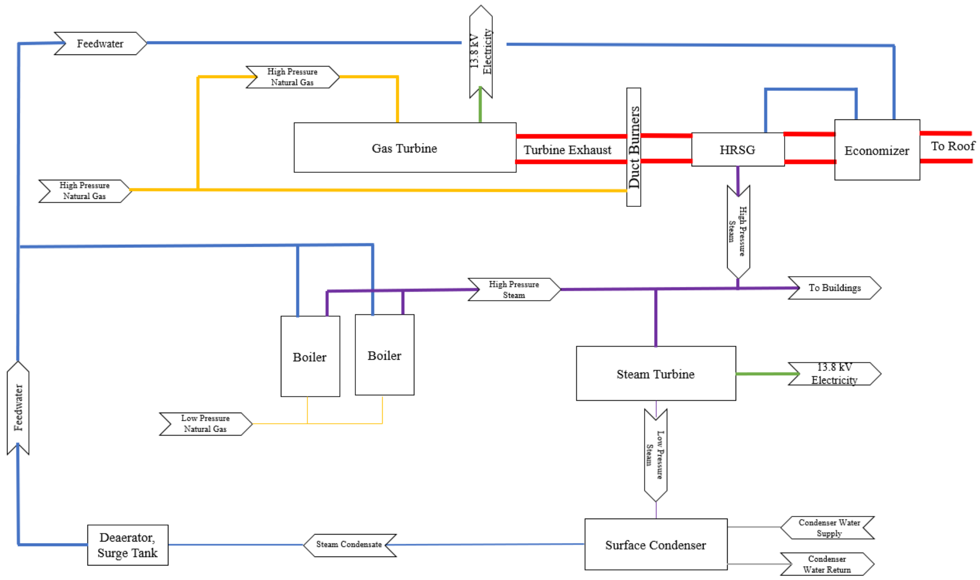


Figure 1: CUP simplified schematic.

A combined cycle power plant such as GW's CUP, uses the exhaust heat from the gas turbine to provide steam to buildings and additional power generation in a steam turbine leading to a higher overall efficiency. Figure 1 is a simplified schematic of the power plant. The plant has been in operation for about three years and since then, a few problems and inefficiencies have been discovered which were not previously expected in the plant design.

The problem can be separated into two categories based on seasons of the year. During the winter, the CUP has a high amount of steam demand for building heating and a low electricity demand from a decrease in air-conditioning use. Currently, there is no method to manage excess electricity. The low electricity demand limits the production of the combustion gas turbine (CGT), which in turn limits the steam produced by the heat recovery steam generator (HRSG). This occurs because exhaust gas from the CGT is not at an optimal temperature of 1250°F [2]. Steam demand is met by supplementing the system with boilers and duct burners, shown in Figure 1. The production of steam from the boilers and duct burners is less efficient than recovering steam from waste heat produced by the CGT. The CGT also has a decreased efficiency when running at a lower capacity.

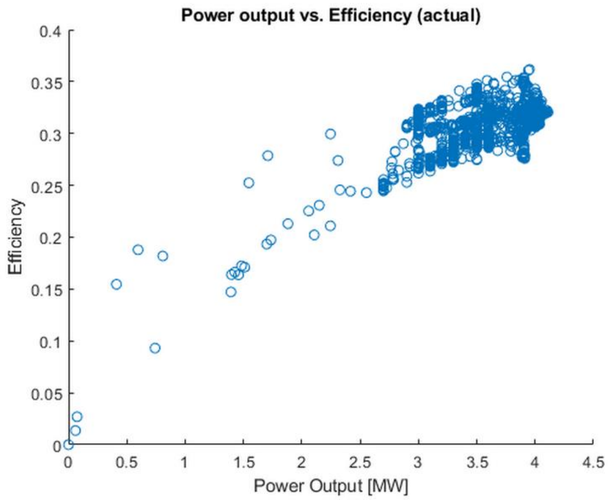
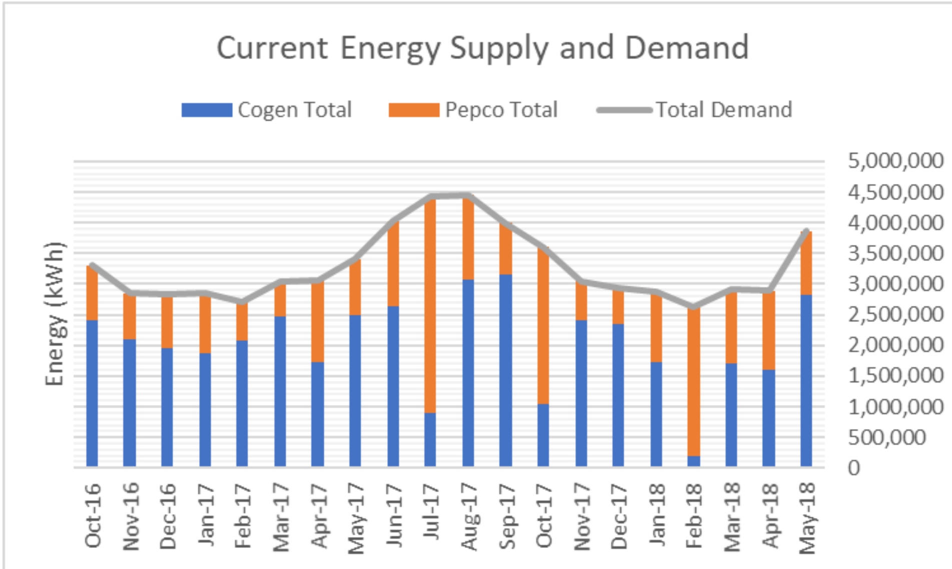


Figure 2: CGT Power vs. Overall Efficiency

During the summer, there is a decrease in demand for heating and an increase demand for cooling, which results in a low steam demand and a high electricity demand in comparison to the winter. In this situation, the plant is limited by the steam demand since there is no method to handle excess steam, aside from an emergency relief valve. The plant is therefore operated at a lower capacity and electricity demand is met by importing electricity from the local utility. This increases unnecessary costs from importing electricity the power plant is equipped to produce. The lower power output of the CGT has a dramatic effect on efficiency, as shown in Figure 2. The CUP also has a unique power constraint, the plant is required to maintain an import buffer with the local utility company, PEPCO. The buffer is currently set at 700 kW, to allow for adequate response time for demand fluctuation. With no way of handling excess power, the power plant is limited to producing 700 kW less than the demand. This limits the utilization of the power plant as there must always be a constant balance between the supply and demand.

Battery Storage

Without the option for net metering (feeding electricity back into the grid), the next option for handling excess electricity is through energy storage systems. After analyzing Figure 3 below, this storage system should be able to handle multiple GWh of excess energy and up to 4-5 MW of power over the course of a year. The maximum capacity in Figure 3 was calculated using the maximum energy produced in a month (September 2017) to find maximum capacity each month. This is the maximum capacity for the current plant with current limitations assuming no shutdowns. The plant has been unable to run at its rated capacity due to its current limitations, but there would be no need for energy storage if it was able to meet its rated capacity.



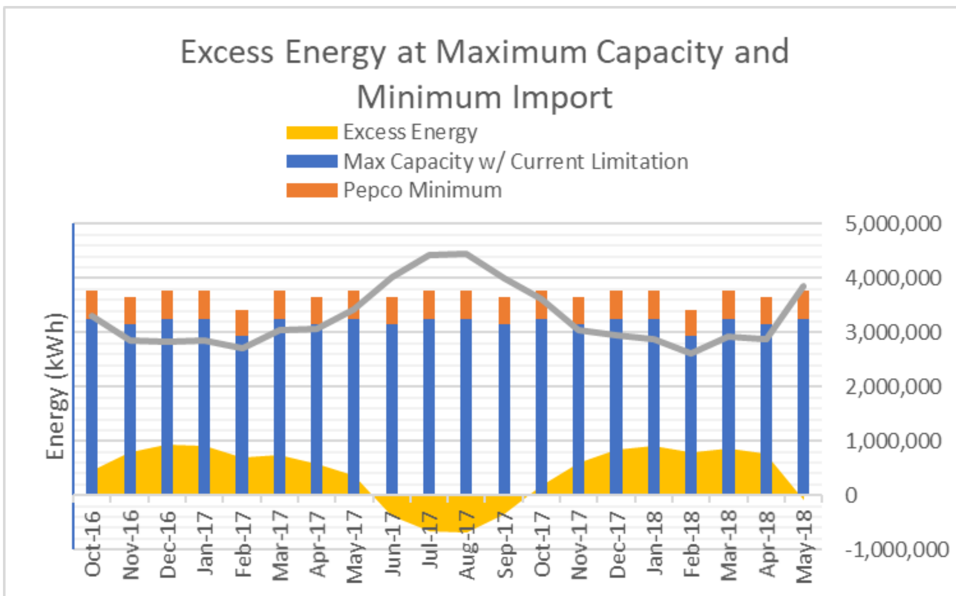


Figure 3: Energy Storage Potential at Minimum Import and Maximum Capacity with Current Limitations

The largest storage systems in the US are pumped storage hydroelectric. The largest of these plants can produce just over 3,000 MW and hold 24,000 MWh but can take years to even get a permit to start building as well as a high capital cost. In the case of an urban power plant like GW's CUP, there is also the issue of transmission and finding the amount of land necessary for this substantial project [3]. Therefore, pumped storage is not usually used for smaller scale power plants like the CUP, even though the system has the capacity to handle the excess load from the power plant.

The most commonly used storage systems for other small-scale combined heat and power plants are utility scale battery storage systems. Lithium-ion batteries are the most common due their maturity, reliability and easy maintenance. They can discharge immediately and store energy for indefinite amounts of time. New technology is making these utility scale battery systems cheaper at prices of 400 to 750 $/kWh [4] and more effective with capacities of 4 to 6 MWh [5].

However, after talking to the Director of Energy Storage and Systems at UCSD, this new technology was not enough to justify implementing 40 ft. shipping containers that are only meant to help with peak shaving and load levelling for a couple hours until needing a recharge [6]. Since the demand for the CUP has never exceed its electrical output capacity of 7.4 MW, the fluctuation in the power demand can be handled by adjusting the natural gas inflow to the plant. Batteries would be effective if the demand exceeded the plant capacity because the batteries would charge at night and discharge during the day when demand is high, but this is not possible with GW CUP's current electricity demand. Further research into battery storage was not continued due to the sizing restraints and ineffectiveness for this CUP.

Steam Bypass System

The other issue of excess steam can be solved by adding a steam bypass system to allow excess steam to bypass the steam turbine and the buildings. The most popular and effective steam bypass system is a dump condenser, a heat exchanger, which condenses the steam from a superheated state to a low-pressure steam or liquid. Steam bypass systems are common in nuclear power plants and CHPs to allow for bypass of steam during transient loads on the steam turbine.

Steam turbines are rated by the pressure and temperature of the steam. The steam turbine runs at a specific speed to produce electricity at the proper frequency. The proper pressure and temperature must be maintained for the turbine to continue to rotate at the proper frequency [7]. A time this pressure and temperature is not maintained is when starting up the turbine. The steam must be rerouted around the turbine during startup because if the steam is not at the proper condition, the steam will condense on the turbine blades and when it's too hot, it may damage the steel, which is originally at room temperature. Due to environmental regulations in metropolitan areas, superheated steam cannot be vented to the atmosphere because it creates a significant amount of noise. The steam is known as flash steam in this state because when it is exposed to the atmosphere, flash evaporation occurs. The temperature and pressure drop simultaneously, and a significant amount of energy is released into the atmosphere [8]. To avoid this problem, a turbine bypass system is needed until the steam conditions meet the inlet specifications of the steam turbine.

A turbine bypass system is used to reduce the outlet temperature and pressure of the steam and provides a route for the steam to travel in the event of steam turbine failure. In a study conducted of the George Washington University's central utility plant (CUP), a dump condenser was suggested to improve the plant efficiency because it will allow the gas turbine to run at full power, even when the steam is not needed to heat buildings [1]. A dump condenser allows steam to travel to the low-pressure condensing tower without passing through the steam turbine or the buildings. This is especially helpful during startup because it allows the steam to bypass the turbine until it reaches the proper temperature and pressure. A dump condenser is a shell and tube heat exchanger specifically manufactured to reduce the pressure and temperature of the steam and can handle the condensing of superheated steam [9]. The current surface condenser is not structurally strong enough to support the condensing of superheated steam. A dump condenser would also require a significant amount of airflow, water, or refrigerant to cool the superheated steam. Water and the refrigerant would then have to be cooled in a cooling tower. If water is used, the water consumption of the plant would increase.,

Functional Requirement

The requirements of implementing a steam bypass system in a model of the CUP are simple due to the versatility offered by using computational methods. The functional requirement is that the design must be able to withstand the maximum mass flow of steam that is expected from the HRSG. This is known to be 40,000 lbm/hr at a maximum load. Realistically, this varies from 23,000 lbm/hr to 35,000 lbm/hr from plant data gathered. In meeting the functional requirements, it is expected that there will be an increase in steam turbine utilization, plant efficiency, and reduced cost of plant operation.

DESIGN DESCRIPTION

The complete design of the CUP with steam bypass system was modeled in MATLAB Simulink to evaluate the potential benefit of the addition of a steam bypass system. The CUP was initially modeled without a dump condenser. The CUP was modeled using a library called Thermolib from EU Tech Scientific Engineering, an add-on to Simulink. The dump condenser was added after the CUP model and components from the Thermolib library were verified to be accurate. The library provides system level modeling capability, and calculates thermodynamic processes using conservation of energy and momentum. This model does not include detailed geometry and is useful for modeling at the system level.

Modeling and verification of the software started with using available data from the CUP components. Other unknown values, such as isentropic efficiency, were found using an iterative process until the data matched the plant metered data. To verify the accuracy of the components in the Thermolib library, each component was verified with manual equations coded in Python to allow for multiple iterations. The Python Cantera library was used to obtain the equation of state for steam, air, and natural gas.

Brayton Cycle

The gas turbine is a Solar Centaur 50 Gas Turbine rated at 4.8 MW. For modeling, the data sheet from the turbine provided pressure ratio, rpm, and maximum mass flow into the turbine. To verify the accuracy of the components in the Thermolib library, each component was verified with equations coded in Python. The Python code assumed an ideal combined cycle power plant to compare inputs and outputs for each component. Air was used throughout the Brayton cycle without the addition of natural gas. This is because the flow of natural gas is typically much smaller than the flow of air, therefore the changes in pressure is expected to be similar between Python and Thermolib calculations.

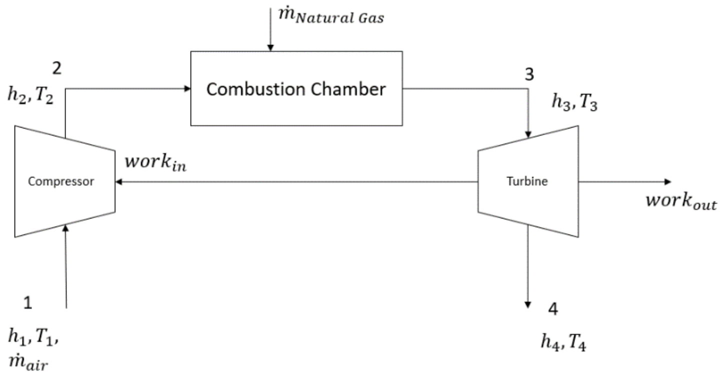


Figure 4:Brayton Cycle diagram of the CGT

Starting with the Brayton Cycle, the compressor and the turbine were analyzed in Thermolib to determine the accuracy of each component. A simplified diagram shown in Figure 4 shows the relative location of each component within the Brayton Cycle. The variables of interest, h_i and T_i represent the enthalpy and temperature respectively at process location i ($i = 1,2,3,4$), while $\dot{m}$ is the mass flow rate.

Thermolib had two isentropic compressors, that when compared to the Python code, showed varying results as observed in Table 1. Efficiency and work required to operate the compressor and turbine is defined in equations 1 and 2. Subscripts "a" and "s" represent actual and isentropic values respectively. From the results in Table 1, isentropic compressor (1) was used from the Thermolib library since the error with the energy balance was only 0.34%.

$$\eta_{compressor} = \frac{h_{2s}-h_1}{h_{2a}-h_1} \tag{1}$$

$$W_{in} = \dot{m}_{air}(h_{2a} - h_1) \tag{2}$$

$$\eta_{turbine} = \frac{h_3-h_{4a}}{h_3-h_{4s}} \tag{3}$$

$$P_{out} = \dot{m}_{air}(h_3 - h_{4a}) \tag{4}$$

Table 1: Thermolib component verification compared with calculated values

Component	Work (MW)	Ideal Work (MW)	Error (%)
Isentropic Compressor (1)	5.86	5.84	0.34
Isentropic Compressor (2)	.0586	5.84	99

In Simulink, the gas input was modeled assuming a steady flow of methane. The combustion chamber was modeled used a mixer to mix air with methane and then a reactor was used to model combustion. The enthalpy of combustion was used to determine the heat and temperature into the turbine which fluctuates depending on the gas flow rate. Whereas, in the Python code, a turbine inlet temperature is assumed to be constant at 1400 K.

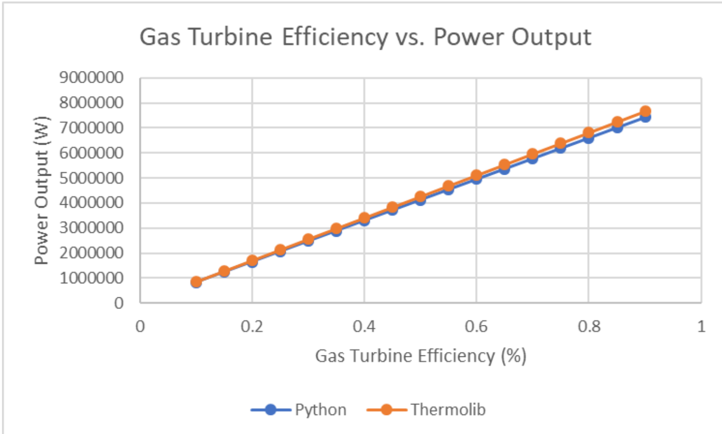


Figure 5: CGT Power Outputs at Varying Efficiencies

To further evaluate the accuracy of the model, actual Combustion Gas Turbine (CGT) data from the CUP was used to approximate fuel and mass flow rate throughout the cycle. The CGT was modeled with reliance on the Cantera library producing the properties of the exhaust gas. With all the inputs coming from the combustion chamber, Cantera used the exhaust pressure (same as inlet pressure of compressor) and exhaust entropy, which due to the nature of isentropic turbines was the same as the inlet entropy, to find the temperatures and power outputs of the CGT at different efficiencies as shown in Figure 5. Using the values found in Cantera and equations 3 and 4, the power that is supposed to be produced from an isentropic gas turbine was found. As evident in Figure 5, the power output from the Thermolib gas turbine matched almost identically with the calculations when compared at different efficiency levels. The GWU gas turbine is rated at 4.6 MW, so even though the power outputs start to marginally diverge after ~6MW, this difference does not impact future simulations.

Heat Recovery Steam Generator

The Heat Recovery Steam Generator (HRSG) was then modeled as the interface between the Brayton Cycle and Steam Cycle, generating steam using the heat from the exhaust gas of the CGT after being supplemented by the duct burners. As with most HRSGs, there are three heat exchangers involved in this process: the superheater, the steam drum, and the economizer. The heat exchanger component in Thermolib was verified by setting the heat transfer rate to the heat exchanger and the environment to zero, assuming no loss of heat to the heat exchanger or to the surroundings. It was assumed that the heat transfer rate out of the Brayton cycle is equal to the heat transfer rate into the steam cycle because there is no heat loss to the exchanger or surroundings. The heat exchanger was able to transfer heat appropriately from hot to cold fluids, and the change in enthalpy of both fluids were equivalent as expected, so it was confirmed that the heat exchanger worked appropriately.

Comparing the HRSG model to the actual CUP HRSG turned out to be more problematic than expected due to the limited data for both the HRSG itself and metered data within the steam cycle. While the data for the inputs and outputs of the flue gas was all given, the UA value for the HRSG, the properties of the inlet feedwater, and the outlet steam were all unknown. To guarantee there was steam coming out of the HRSG, a PID controller was used to superheat steam past the liquid vapor region by setting the target temperature to 500 K. This allows for steam production from the HRSG to analyze the steam cycle and steam bypass system appropriately.

Steam Cycle and Steam Bypass System

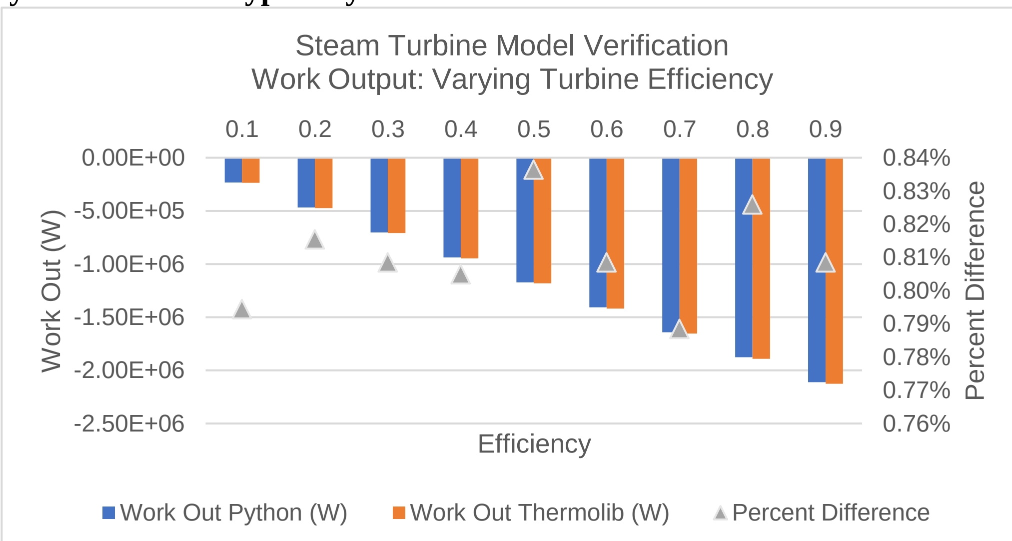


Figure 6: Steam Turbine Model Verification - Work Output Varying Turbine

After the water is heated to steam in the heat recovery steam generator, the steam is routed through a steam turbine, producing mechanical work by spinning the blades of the turbine. The steam turbine was assumed to be isentropic and adiabatic, meaning there is no heat loss from the turbine to the surroundings. These assumptions will lead to an increased work output when compared to actual metered readings. For the purpose of verification, the values used were on the same magnitude as the values in the metered data and the specification sheets for the Dresser Rand 2.8 MW turbine. The work output of the turbine was calculated manually using Equation 5. Equation 5 shows the turbine work out in watts is equal to the turbine efficiency times the mass flow rate in kilograms per second times the change in enthalpy across the turbine in joules.

$$\dot{W}_{out} = \eta\dot{m}(h_{out} - h_{in}) \tag{5}$$

The efficiency of the turbine was changed at an increment of 0.1 from 0.1 to 0.9 and the work output was recorded. The same inputs were used in the Simulink model and the efficiency was varied at the same increment. A comparison of the results can be found in Figure 6. The work out was negative in the manual calculations and in the Simulink model, maintaining the same sign convention. As the efficiency increased, the work output increased as expected. All percent differences were less than 0.9% with no correlation between the percent difference of different efficiencies. The percent difference between the manual calculations and the simulation were insignificant on a kilowatt scale and were most likely due to rounding. The steam turbine was verified to operate properly in the simulated model at the pressures and temperatures of a real combined cycle plant.

After the steam leaves the turbine, it is routed to a shell and tube surface condenser. The condenser was modeled as a cross flow heat exchanger. For testing and verification of the heat exchanger component, the heat exchanger was assumed to be thermally massless and absorb no heat but Thermolib does not allow for a completely massless heat exchanger. The heat transfer rate to the heat exchanger was set to zero, having the same effect as being thermally massless. The heat exchanger was also assumed to be isobaric for both fluid flows. The values of the inputs were obtained from the Ambassador Surface Condenser data sheet. The results of this simulation are available in Figure 7. As expected, the steam, input 1, was cooled to a lower temperature at

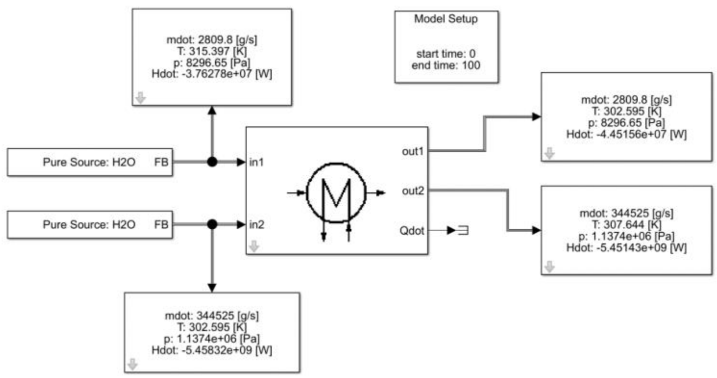


Figure 7: Condenser Simulink Simulation Results

the same pressure and the cooling water, input 2, increased in temperature at the same pressure. The change in enthalpy of the steam and the cooling water were both 6.89 MW. The change in enthalpy of each fluid is equal if all the heat was transferred only between the fluids.

After each major subsystem was modeled, the subsystems were put together to make a final CUP model in Simulink. This included adding a boiler, feedwater tank, and thermal mass to represent the buildings that heat is supplied to.

Complete CUP Model with Steam Bypass

The individual components were then compiled to generate a complete model and compared to CUP data. In order to determine the relationship between the fuel flow in the gas turbine and power output of the plant, the combustion gas turbine fuel flow rate (scf/hr) and average power was collected from June 1 to August 14, 2018. The average power output was plotted against fuel flow rate to approximate a relationship between the power generated and fuel flow. Appendix A shows a plot of the data and polynomial used to determine the fuel control for the model. The polynomial fit allowed for fuel flow rate in the model to be estimated based on demand and was implemented in the CUP model when the subsystems were combined.

Using this technique in the Simulink model, the demand for one month of data was imported to the model and the polynomials were used to determine the power settings of the compressor and the fuel flow rate. The efficiencies of the compressor and turbine were adjusted until the power output in the simulation closely matched the demand from the actual data gathered from the CUP. Actual compressor and turbine section efficiency data was unavailable. The isentropic efficiency of the compressor and turbine were set to 90% and 83% respectively. In the model, heat losses were not considered in the combustion chamber, compressor, and turbine.

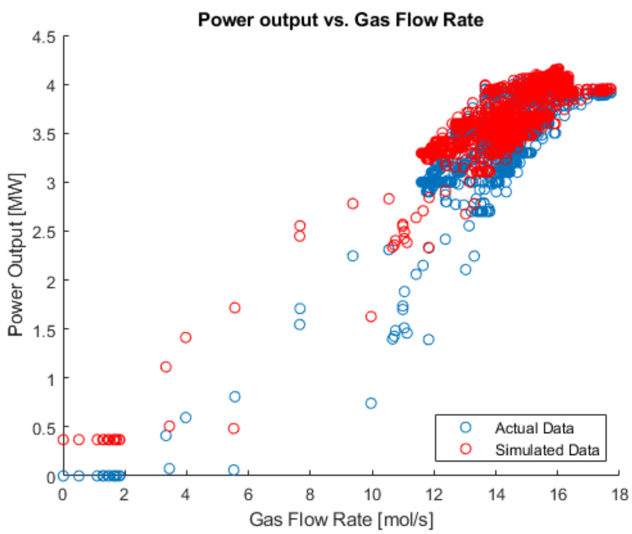


Figure 8: Simulated power output plotted against gas flow rate and compared to the actual demand and flow rate for the CUP gas turbine.

The results in Figure 8 shows that the model created in Simulink closely reflects the gas turbine operation for the 3 MW to 4.2 MW range. The data diverges when the demand falls below 3 MW. This is due to the modeling capability in Thermolib.

Next, the HRSG and associated steam cycle was added to the model. This proved to be very difficult as there was limited information on the quality of steam and the HRSG specification. This led to a large inaccuracy in the model since the steam turbine was unable to produce greater than 1 MW of power. This is shown in Figure 9 and described more in detail at the end of the paper.

After the model of the current power plant was completed, the design solution of a dump condenser was added. This offers a steam bypass for the system where excess steam produced in the summer months can be returned to the feedwater system. The dump condenser was placed along with a hydraulic directional control valve to control the amount of steam going to the steam turbine and to the dump condenser. This was controlled by a value between 0 and 1 in the Simulink model. Figure 10 shows the steam bypass subsystem that was added along with the efficiency change.

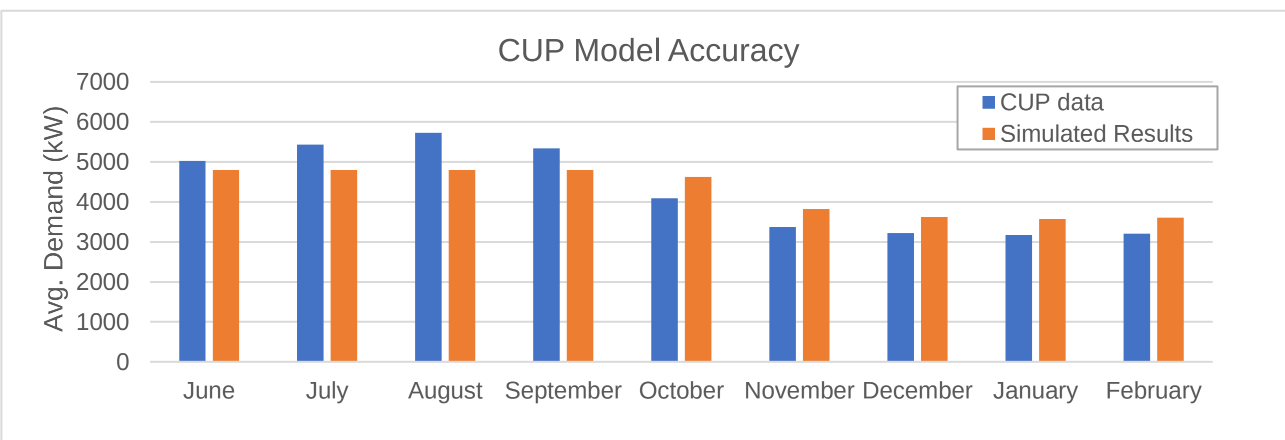


Figure 9: CUP Model output compared to actual CUP output. The maximum output of the model is limited to 4.7 MW.

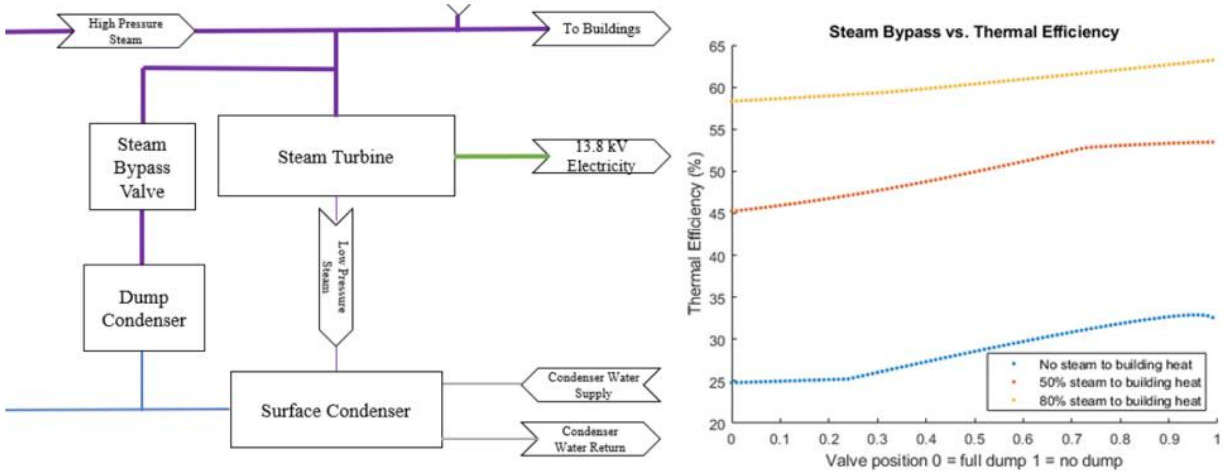


Figure 10: Steam Bypass system and dump condenser (left) and thermal efficiency change with bypass system valve position (right).

Modeling the Dump Condenser and Control Valve

The dump condenser was modeled as a heat exchanger in Thermolib. The heat exchanger requirements were determined based on the requirement that the water exits the condenser in a saturated liquid state. Then the water is routed back to the feedwater system for reuse in the Rankine Cycle.

A steam bypass system will need to have the ability to handle up to 50,000 lbs/hr of superheated steam. The dump condenser will be used most during the summer, when the electricity demand is high, and the steam demand is low. However, the condenser will typically have a load of about 20,000 lbs/hr during the summer. The steam turbine has a minimum output of 500-750 kW and must have an adequate steam flow to produce this. During the winter when electricity demand is low, the gas turbine can run at a higher speed, making it operate more efficiently, producing more steam in the HRSG, requiring less steam production from boilers to heat buildings. Any remaining steam is routed through the dump condenser rather than the steam turbine. Since there is a maximum mass flow through the steam turbine of 12,000 lbs/hr of steam, the plant control system will need to be adjusted to control the valve installed between the turbine and the steam bypass system. The control system for the bypass device only allowed a maximum of 12,000 lbs/hr of steam to reach the turbine. When the amount of steam exceeded 12,000 lbs/hr, the valve would maintain 12,000 lbs/hr of steam to the turbine and the remaining steam would be passed to the bypass device. In addition to steam, there must be electricity demand for the electricity produced in the steam turbine, otherwise the steam will be routed through the bypass device.

Steam Bypass System Functionality

The dump condenser within the steam bypass system was first verified by ensuring the steam exits the condenser in a saturated liquid state. This was done by using the fluid state in

Thermolib. Next, the control system for the dump condenser was evaluated. It was important to show the valve would open to allow bypass when steam flow to the steam turbine exceeded 12,000 lbm/hr., the physical limit of the turbine. This was done by monitoring the output of the steam turbine when the flow rate exceeded 12,000 lbm/hr. Table 2 shows the simulations completed for 9 months of data. CUP power averages is the average output of the CUP from June 2018 - Feb 2019. The model is limited in the power output and is unable to accurately estimate the power output of the CUP. This is primarily due to lack of information about the HRSG and steam quality. This error will not affect the model's ability to show how excess steam will be managed. In the column, Steam Turbine Output, the data shows that the steam turbine can turn on and off based upon the power demand and steam flow in excess of 12,000 lbm/hr.

Table 2: Steam bypass function check, the output of the steam turbine is zero when the bypass is open.

Trial	*CUP Power Averages (kW)*	*Simulated Power Output (kW)*	*Steam Turbine Output (kW)*
1	5725.78	4670.58	852.50
2	6131.05	4670.58	852.50
3	6427.60	4670.58	852.50
4	6038.43	4670.58	852.50
5	4790.32	3801.16	0.00
6	4064.65	3196.37	0.00
7	3917.55	3091.34	0.00
8	3876.30	3062.04	0.00
9	3906.79	3083.69	0.00

EVALUATION AND TESTING

The CUP model in Simulink was evaluated and tested based upon available plant data from June 2018 to January 2019. The steam bypass system was evaluated based on three criteria that fall within the functional requirement to handle excess steam produced. The steam bypass system must show that the steam is condensed to a saturated liquid state and should improve the overall efficiency of the power plant. It is also expected that there will be an increase in the utilization of the steam turbine, output of the CUP, and reduce the cost of operation.

RESULTS

Effect on Steam Turbine Utilization

Another potential benefit that needed to be evaluated and determined was the effect on utilization of the steam turbine. As stated previously, the GW CUP must maintain a 700 kW import of electricity from the PEPCO. In order to save the most money, this should be kept at 700 kW, however, this is often not the case. In the summer, excess steam would be created if the gas turbine operated to meet demand. Therefore, the power output of the plant decreases and more electricity is imported. The model was used to simulate the power output of the CUP with the assumption that the steam turbine would make up for demand greater than 4.2 MW. The idea was that maintaining the import of electricity to 700 kW will increase the utilization of the steam turbine. Utilization is a ratio of the power output to the rated power output of the steam turbine [1].

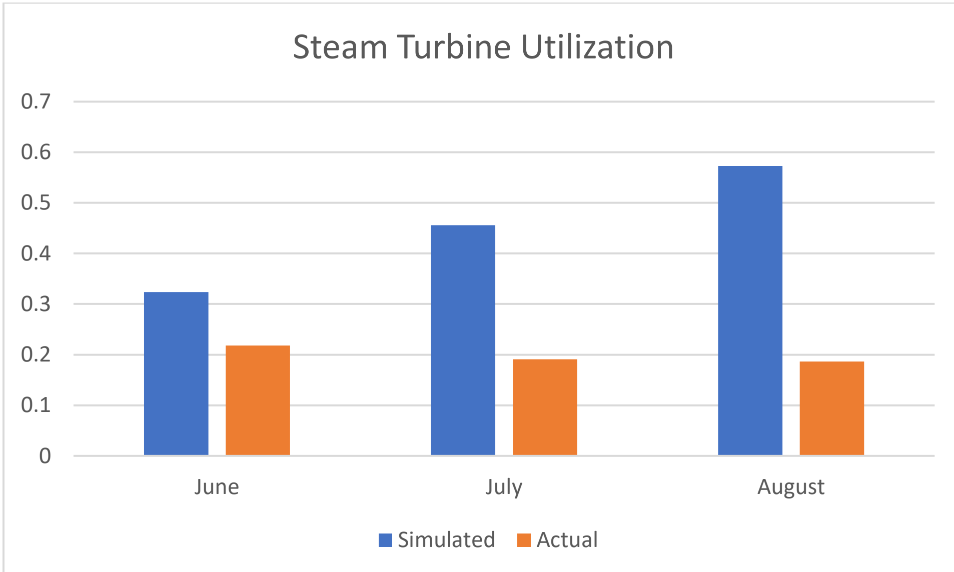


Figure 11: Utilization change of the steam turbine with a steam bypass system for the summer of 2018.

Figure 11 shows the change in utilization of the steam turbine with a dump condenser added to allow excess steam to bypass and maintain the minimum 700 kW of imported electricity. For the summer months of June-August of 2018, there is a projected increase in utilization of the steam turbine. Utilization is an important metric because the CUP is a more cost-effective way for GW to have electricity. Therefore, increasing utilization will be reflected in reducing electricity costs. This increase in steam turbine usage is coupled with an increase in Gas turbine output and gas usage.

Steam Bypass System Effect on Brayton Cycle Efficiency

The importance of increasing gas turbine output lies within the Brayton Cycle efficiency. It is clear from plant data shown in a previous suction, that the efficiency is optimal when the gas turbine operates near the maximum capacity, greater than 3MW.

Gas Usage Change

Since more steam would be produced during the summer, the natural gas usage of the gas turbine would change. This would change to 50089 SCF/hr when the gas turbine is operating with an output of 4.2 MW. This would increase the amount of money spent on gas but would lower the amount of electricity imported. Table 3shows the projected cost savings if the CUP were able to operate with a steady 700 kW import from the utility company. A supplemental table is in Appendix A that has ideal imported electricity and gas usage values.

Table 3: Projected Savings at Minimum Electricity Import

Rates	Cost per kWh/therm	Usage	Cost
kWh Charge	$0.0995492	9371862.30	$932,961.39
Demand Charge	$10.82	40187	$434,826.52
Gas Cost	$0.4592	1071948	$492,238.40
Total			$1,860,026.31
kWh Charge	$0.0995492	4099200	$408,072.08
Demand Charge	$10.82	5600	$60,592.00
Gas Cost	$0.4592	1170678.7	$537,575.65
Total			$1,006,239.73
Estimated Savings			$853,786.58

Efficiency Benefits from Steam Bypass

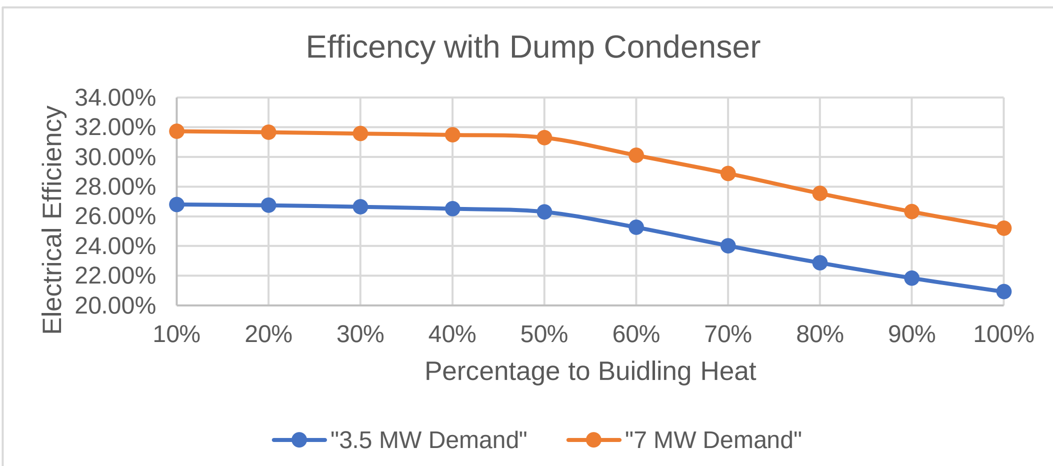


Figure 12: Model change in electrical efficiency with dump condenser with varying power

The increase in steam turbine utilization directly relates to an increase in plant efficiency. With a steam bypass condenser, the plant's electricity production will only be limited by the electricity demand and not the steam demand. The bypass will allow the gas turbine to run at its maximum speed, providing the greatest efficiency. The plant was simulated with an input of 3.5 MW and 7 MW power demand with no boiler output. The percentage of steam delivered to the buildings was changed and plotted in Figure 12. At 50% of steam to building heat, less than 12,000 lbs/hr of steam is traveling to the turbine-bypass valve, therefore all the steam goes through the turbine if there is a power demand to support it. It was expected for an increase in efficiency at 7 MW when compared to 3.5 MW.

In order to compare the CUP performance with a dump condenser to the CUP without a dump condenser, the Simulink model was compared to an identical model without the dump condenser. This allowed for the steam bypass system to be evaluated without inaccuracies present between the actual plant and the model. Table 4 shows the change in efficiency of the CUP model with and without the dump condenser. There is a larger increase in thermal efficiency when the demand is at 5 MW than when the demand is lower at 2 MW. The dump condenser leads to an increase in thermal efficiency of the plant.

Table 4: Comparison of CUP model efficiency with and without dump condenser

Demand (MW)	Thermal Efficiency (W/ Dump)	Thermal Efficiency (W/o Dump)
5	0.3992	0.3209
4	0.3524	0.3275
3	0.3064	0.2876
2	0.2172	0.2089

SUMMARY CONCLUSIONS, AND RECOMMENDATIONS

The Central Utility Plant at George Washington University presents a unique challenge in managing electricity and heat requirements for the associated buildings. The location of the plant inhibits the ability to propose a large subsystem to handle excess steam. Also, the inability for net metering restricts the full potential of the 7.4 MW plant. Through system modeling of a bypass system, a dump condenser was shown to present an effective way of handling the excess steam. This was shown in the increase of utilization of the steam turbine, as well as the expected reduction in cost associated with reducing the amount of imported electricity.

A dump condenser is effective in improving the plant's overall utilization leading to improved efficiency because it can operate at its designed capacity. The dump condenser allows for the plant to meet the demand without steam limitations, specifically during the summer months when power demand is high and steam demand is low. The dump condenser increases the plant safety as well, providing a means of condensing the steam without overheating buildings or receiving fines from venting, in the event of a malfunction of any steam producing or handling device.

RECOMMENDATIONS

The HRSG in the model does not reliably produce steam. The HRSG was modeled using three heat exchangers connected in series and the data of the actual HRSG is not available. The UA values of the HRSG were controlled using a PID control loop which maintains the output of the HRSG at steam. By obtaining the specifications of the HRSG, the model will be more realistic. This may be accomplished by having a separate project to develop a custom block in Simulink of the HRSG to add to the Thermolib library.

Collecting more data of the actual performance of the powerplant and its control will aid in developing a more realistic model. In the model, the input of power demand is not equal to the plant output because there is no control to account for the losses due to efficiency in the plant. This is a major consideration, especially due to the heat loss in having the gas turbine exhaust travel in a duct, bending 180 degrees to the heat recovery steam generator. In the current model state, there is no control of the gas turbine based on the steam produced, but the bypass steam valve is controlled by the power demand.

The steam turbine in the model does not produce the maximum power output at the maximum steam flow rate. At 12,000 lbm/hr, the model outputs about a megawatt of power when the real steam turbine has a rated capacity of 2.8 MW, this leads to an underestimation of power output and efficiency in the model. The control of the steam turbine in the plant is currently automated and operates off the principle

A dump condenser has been proven to be effective in increasing utilization. Further work will need to be conducted in the detailed design of the condenser and if the current cooling towers can handle the additional cooling for the dump condenser.

APPENDICES

Appendix A: References

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Appendix B

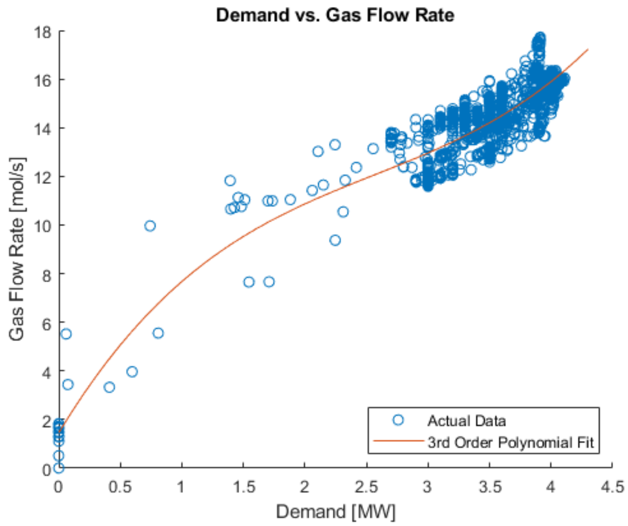

Figure A1: CGT demand plotted against fuel flow.

Figure A1 above is the plotted demand and gas flow data for the gas turbine from June 2018 to August 2018. This was used to determine the relationship between gas flow and power output of the turbine. The polynomial was used in the model to convert demand to gas flow rate in order to obtain the proper power output of the gas turbine.

Table A1: Financial analysis table, shows values used to calculate cost associated with CUP.

GS 3A	$/kWh or $/therm	June (kWh)	July	August	September	October	November	December	January	Cost
Kwh charge	0.0995492	943475	1644909	2129932	1620448	1221589	608704	665932	536872	$932,961.39
Demand Charge	10.82	4542	7026	6712	7058	5261	4232	4143	1213	$434,826.52
Gas Cost	0.4592	151,739.28	140,670.43	141,652.25	141,652.25	125,862.14	126,228.17	120,853.20	123,290.01	$492,238.40
		948,017.37	1,651,934.86	2,136,643.98	1,627,505.69	1,226,850.06	612,936.59	670,075.78	538,085.26	$1,367,787.91
Projected										
Kwh charge	0.0995492	504000	520800	520800	504000	520800	504000	520800	504000	$408,072.08
Demand Charge	10.82	700	700	700	700	700	700	700	700	$60,592.00
Gas Cost	0.4592	156,858.96	163,711.16	162,471.85	157,889.38	144,159.24	128,111.44	134355.5554	123121.1067	537,575.65
										468,664.08
Savings	$ 853,787								Total	$1,006,239.73
									Total	$1,860,026.31

Table A1 shows the analysis of the estimated cost of power with the steam bypass system compared to the cost from June 2018 to January 2019. The numbers under each month is the energy used in kWh, kWh charge is the average $/kWh for June 2018 to January 2019. The demand charge is a usage charge calculated by PEPCO where the maximum demand in kW is multiplied by the charge ($/kW). The gas cost is given in $/therm and the gas usage for each month is given in the same row in therms.

Appendix C

Python Code for Brayton Cycle Calculations

```
# -*- coding: utf-8 -*-
"""
Created on Fri Mar  8 13:49:03 2019

@author: welch
"""

import numpy as n
import cantera as ct
import matplotlib.pyplot as plt

air = ct.Solution('air.cti') #defines the properties of air

def enthalpy (fluid, T, P):
    fluid.TP = T, P
    h = fluid.enthalpy_mass
    return(h);

def brayton():

    PR = 10
    P1 = 1E5
    T1 = 300
    P2 = PR*P1
    P3 = P2
    T3 = 1056.51
    eff = 0.9
    eff_t = 0.85
    air.TP = T1, P1
    h1 = air.enthalpy_mass
    s1 = air.entropy_mass

    s2 = s1
    air.SP = s2, P2
    h2 = air.enthalpy_mass
    h2a = (h2 - h1)/eff + h1
    air.HP = h2a, P2
    T2 = air.T
    s2 = air.entropy_mass
    air.TP = T3, P3
```

```
    s3 = air.entropy_mass
    h3 = air.enthalpy_mass

    s4 = s3
    P4 = P3/PR
    air.SP = s4, P4
    T4 = air.T
    work_in = 3.1*(h2a-h1)
    work_in2 = 18.8*(h2a-h1)
    print(work_in)
    print(work_in2)

    h4 = air.enthalpy_mass
    h4a = h3 - (h3-h4)*eff_t
    work_out = 19.0035*(h3-h4a)
    print('Work_out: {0}'.format(work_out))

    return s1, h1, T2, s2, P2, h2, s3, P3, h3, s4, T4, P4

def main():
    brayton()

if __name__ == '__main__':

main()
```