SELLING SMART WITH MICROGRID EXPANSION AND DATA ANALYSIS: A

CASE STUDY OF THE RUTGERS BUSCH AND LIVINGSTON MICROGRID

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ABSTRACT OF THE THESIS

Selling Smart with Microgrid Expansion and Data Analysis: A Case Study of the Rutgers Busch and Livingston Microgrid

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The deteriorating electrical grid has long been a focus and concern for the Energy Sector. Although a complete overhaul of the electrical infrastructure would be beneficial, it is not currently feasible. This has led to a rigorous search for alternative solutions to the growing grid failures. A unique solution comes in the form of analysis focusing on remedying current grid congestion obstructions with the prospect of incorporating existing microgrid systems for economic benefit. Two distinct Cases are analyzed – the former pertains to inserting new generation into the electrical grid at points with strong congestion percentages within the LMP (Locational Marginal Pricing), while the latter uses an existing microgrid system and expands upon its current generation. The sample microgrid system utilized for analysis was the Rutgers Busch & Livingston Microgrid consisting of a cogeneration plant and multiple photovoltaic solar systems. The strong differentiator between the two Cases is that the first prioritizes economic benefit entirely while the second initially satisfies the internal microgrid load before seeking financial profits. A congestion pricing model was derived to demonstrate the fluctuations in price with respect to new generation. Data from a variety of existing nodes within the PJM grid was studied in combination with the Rutgers microgrid historical data. It was found that economic success was most prevalent at the node with a positive congestion pricing percentage above 2%. This was consistent in both Cases despite the second case having a primary focus on internal fulfillment. The congestion pricing was the principal influencer in the financial success of the new generation incorporation.

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Chapter 1

Introduction

1.1 Motivation

As America's economic focus shifted to external protection and defense, the state of our internal electrical facilities has been waning; specifically, the condition of the electrical infrastructure. As of 2018, the United States defense budget was roughly $670 billion ("Fact Sheet 2018," 2018) while the 2018 trillion-dollar infrastructure plan entirely ignored the electrical grid ("$1.5 trillion," 2018). With more frequent blackouts, cascading grid failures and unclear risks to cybersecurity-based attacks, we need to look into the future of the electrical grid and its evolution. Both Moslehi & Kumar (2010) and Hosseinzadeh et al. (2017) discuss the harrowing point that we have a significantly larger blackout rate than all other developed countries. The problems facing the energy grid are continuously growing as technology evolves while the grid infrastructure remains stagnant, deteriorating in contrast to a world moving forward.

Microgrids are one of the many directions being explored for the future of the American infrastructure. Generally, microgrids attraction is strongly due to the opportunity for cleaner, renewable energy generation such as solar. However, socially driven motives are not enough for widespread microgrid adoption without the lure of economic incentives. Financially smarter microgrid implementation provides the opportunity for profit by intelligently designating generation in response to real-time grid pricing, operations and demands.

1.2 A background on microgrids

A microgrid can be defined in many ways. There are no specific state or federal restrictions or regulations which constrict a microgrid to a specific size, location or dimension. However, there are generally agreed upon characteristics an electrical system must possess to be define by the term microgrid. Goranović et al describes it as “a cluster of loads, decentralized energy resources (DER) (e.g. PV panels, diesel generators, gas turbines) and energy storage system (ESS) (e.g. battery, fly wheel), which are operated in coordination to supply electricity reliably.” Whereas Dundas and Wang define microgrids as “a system of interconnected loads and local generation which can operate independently of the general utility grid.” The former is more focused on the specific entities while the latter relies on autonomy. The definition being used here defines microgrids very similarly to Dundas in Wang, as a network of distributed energy sources – consisting of dispersed generation as well as optional scattered storage – which are controlled by a decentralized system and has the ability to disconnect from the electrical grid as a whole and be at least partially self-sustaining – or islanding. Islanding in this frame meaning the microgrid can support all vital operations within its system but not 100% of the load – all vital operations are kept functioning while inconsequential loads are turned off. In briefer terms, there are three key characteristics possessed by all microgrids: self-generation; self-controlled systems; islandable.

1.2.1 Traditional applications

We consider first a brief history of a microgrid's traditional applications and functionalities. It is important to note that as of 2018, "only a few states in the United States have dedicated funding for microgrid projects. These include Connecticut, Massachusetts, New York, New Jersey, Maryland and California" (Dundas & Wang, 2018). However, recent papers have evaluated the advantages microgrids bring about. Microgrids have dual-advantages in the sense that they benefit both utilities and consumers. For utilities, microgrids reduce the overall demand needed to be met by generation plants – specifically during peak demand periods – as well as reduce the overall losses in the system by avoiding long transmission and distribution line travel. "Overload of certain segments of the electric grid is one of the main causes of power failure and blackouts" (Ibars et al., 2010). As of 2013, the United State has one of the highest System Average Interruption Duration Index (SAIDI) rates for outages out of any developed country (Dundas & Wang, 2018). For the consumers, "…application of the microgrid…can improve network quality, reduce emissions and can reduce the cost to be incurred by the user" (Hartono et al., 2013). Microgrids also allow for the utilization of a DG/DS – Distributed Generation / Distributed Storage – system which can promote the use of greener and more efficient generation sources such as photovoltaic solar systems and wind turbines.

Previously, communities installed microgrids to combat outage concerns and lower energy costs through local generation, as well as deal with remote location access to power – much like the Multi-Microgrid system being developed in a rural area of Oman (Hosseinzadeh et al., 2017). However, new demands on the grid pose microgrids as a refreshing new direction to push towards. The necessity draws from the rising number of and power requirement from everyday electronic devices as they have drastically increased the load on the whole grid, or macrogrid, over the past decades.

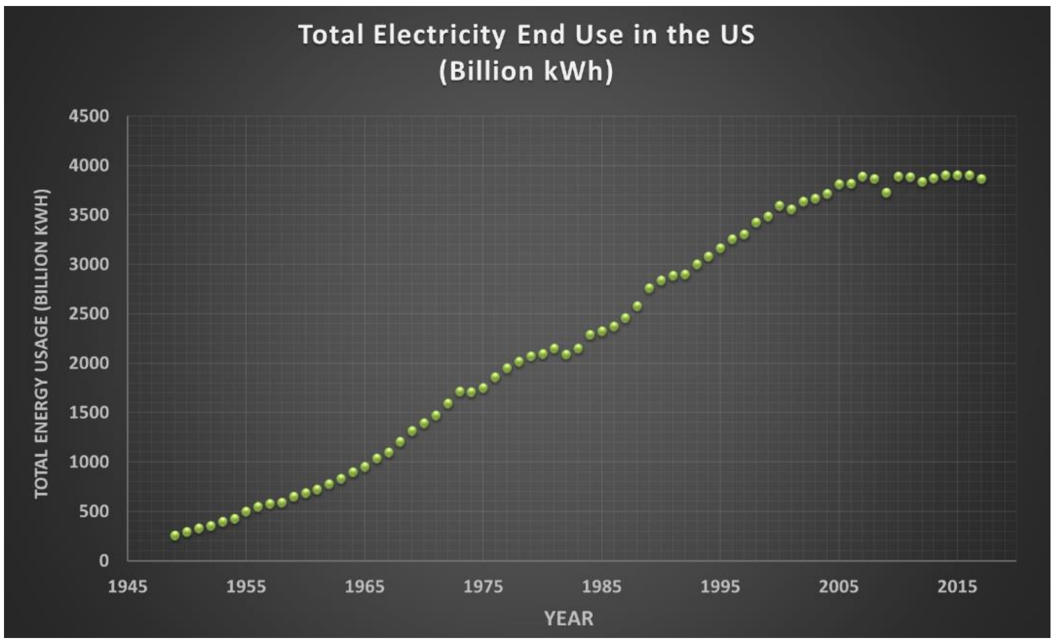


Figure 1: United States Electricity Consumption from 1949 to 2017 as reported by the U.S. Energy Information Administration (EIA) ("Total Energy Annual," n.d.)

Figure 1 shows the fairly steady rise in electricity usage since the 1940s. Despite this overt increase, the infrastructure has not changed much since the 1960s which is decades before the time of modern-day computers and phones (Zhu et al., 2005). In recent years, the increase in demand has begun to level off, however, we have yet to catch up to the prior demand escalations from decades before. Additionally, the decentralization of energy production through DERs, such as residential photovoltaic (PV) systems, drastically changes the flow of an already congested network. The grid needs to adapt to the increasing duality of entities in the grid, where users can be both consumer and producer (prosumer) and loads, such as energy storage systems and electric vehicles (EVs), can both give to and draw from the grid. Microgrids counter these problems with a dynamic and decentralized approach to control and management.

1.2.2 SMART microgrids

Given that microgrids are a strong contender for the future of the American grid, a further step is the concept of SMART microgrids. The traditional grid design in Figure 1 displays the straight-line method of electricity generation and distribution used today. Electricity is generated, transported and distributed out to residences, commercial buildings and industrial complexes (Ibars et al., 2010).

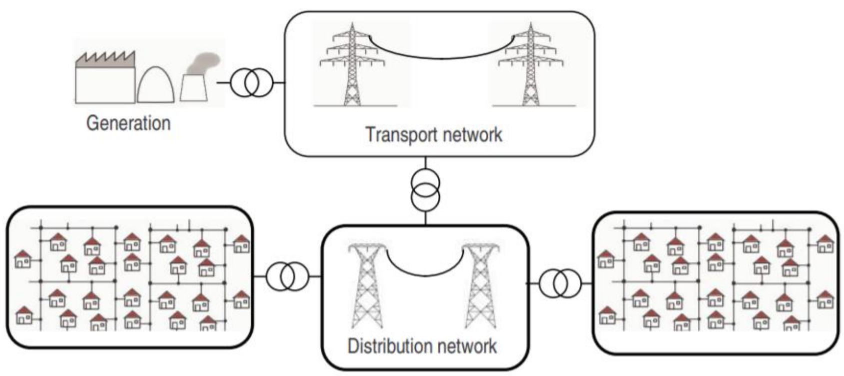


Figure 2: Current grid structure
[adapted from (Ibars et al., 2010)]

Although this traditional infrastructure design has been the backbone of the grid for decades, there has been a shift towards a more distributed system. Personal generation – whether it be rooftop solar or in-house combined heat and power generators (CHPs) – has become more widespread. Smart meters – which track energy import and export – are being incorporated into these individual systems for the purpose of energy rebates and net metering. Net metering is when energy companies track and charge individual energy usage through the difference between the amount imported versus the amount exported (Hartono et al., 2013). The current design allows for unused, excess generation to be put back into the grid to be used by others sources.

SMART grids incorporate a living digital layer that is currently lacking in most established microgrids. This style of layered design would allow for future growth and opportunities to expand on SMART features in the future. Net metering and self-generation may be accompanied by a relatively new concept of Peer-to-Peer energy trading which occasionally complements SMART microgrid infrastructure. In order to accommodate any of the peer-to-peer trading models in circulation a power routing system is necessary which "involves transporting power from a source (seller) to a destination (buyer) which may be geographically located far away from each other" (Abdella & Shuaib, 2018).

1.3 Economics of the PJM Market

Power pools, or power exchanges, are an interconnection of utilities which manage wholesale trading. These power pools developed into Independent System Operators (ISOs) which are non-profit third parties who manage power transportation to ensure all loads are met and to avoid any bias-selling or insider trading; they play no part in the individual power plant generation handled by utilities ("What is a," 2019). PJM is the ISO covering New Jersey, Pennsylvania, Maryland, Delaware, Washington D.C., West Virginia, Ohio and parts of Indiana, Illinois, North Carolina, Tennessee, Virginia, Michigan and Kentucky. PJM's main purpose is to coordinate the needs of the consumers with the capacity provided by the generators. The grid is split up into nodes

PJM runs three distinct markets – The Electricity Market, Ancillary Services Market and Capacity Market.

- The Electricity Market handles about 2/3 of the electrical load for the region. Generators provide price bidding curves in the Day-Ahead and Real-Time Market setups to compete into the pool with all other generators. The bidding curves are determined by the power plants and based on the megawatts generated. Generally, as megawatt capacity increases, the cost per megawatt increases. PJM selects the generators based on the lowest pricing until the predicted load is met ("Understanding the Differences," 2019).
- The Ancillary Services Market handles the remaining on third. It consists of spinning reserves which "…are generation resources that can quickly come online … within 10 or 30 minutes in the event of an unexpected loss in generation. These operating reserves also help balance the system in emergency situations" ("Understanding the Differences," 2019).
- The Capacity Market is designed to accommodate for future load growth. The ISO researches load prediction models to forecast where demand will increase the most and where new generation should be installed.

The Ancillary Services Market is the main location where microgrids could strongly contribute and generate revenue. With an increase in brownouts and blackouts as mentioned, microgrids can take advantage of these opportunities by supplementing the load. Where generators suddenly go out – or congestion points suddenly spike – excess generation from microgrids can play into the market for profit.

1.4 Primary Focus

This thesis focuses on the viability of incorporating new power plant assets into the whole grid, as well as integrating expanded generation into an existing microgrid. It first explores opportunities available for installing new generation at a given point in the grid. The economics are evaluated to see how profit can be made by taking advantage of congested areas. These areas in the grid have large electrical demands which are limited – and become congested – due to a transmission line capacity smaller than the load. This congestion leads to a spike in electricity prices in these areas which new generation can take advantage by selling into the grid at these points. Next, new generation is implemented into a preexisting microgrid to evaluate economic benefits for an existing system. For the purposes of this thesis, the Rutgers Busch and Livingston Campus Microgrid will be used as a sample.

Two distinct cases were evaluated. Case 1 is based solely on economic advantages related to smart generation and export under existing grid stresses – specifically a focus on congestion pricing. Case 2 puts the self-sustainability of the Rutgers microgrid first, with a secondary focus on optimal economics. Both cases are evaluated amongst three different nodes within PJM's territory (discussed more in Chapter 2.1) – Nodes A, B and C –rely on the nullification of a current PSEG 1MW minimum purchase contract that Rutgers has in place which is discussed in more detail in the following section. A cost analysis was performed to compare the pricing between the cost to generate versus electricity costs in the grid each hour. If the electricity cost was above the generation cost, that hour was deemed a viable economic hour. Because congestion pricing is largely based on the megawatt load at a given node, the effect of increased generation on congestion was evaluated and accounted for through a decrease in the pricing. This will be discussed further in Section 2.2.2.

By evaluating an increased megawatt capacity at multiple nodes as well as in conjunction with the Rutgers campus, multiple economic hours were present to produce a favorable revenue under assessed conditions. Through varying the generating cost and its associated variables, as well as varying the megawatt expansion size, an optimal system size was determined for both Case 1 and Case 2. After thorough data modeling, the results provided clear insight into new power generation placement. It was found that for Case 1, Node A provided the best prospects for revenue in comparison to both Nodes B and C. An optimal generating cost of about $28.47/ MW was obtained first which led to an optimum 26MW of new turbine generation and a net revenue of almost $90,000. For Case 2, Node A also was superior to Nodes B and C. A larger system of 97MW and a lower associated generating price of $25.34/MW was found to be optimal and could achieve a net revenue of almost $55,000 while also fully satisfying the Rutgers microgrid load.

This thesis evaluates the economic and technologic advantages of incorporating new generation through microgrids into the electrical grid infrastructure and has determined which design cases would produce favorable economics for a specific microgrid system.

Chapter 2

Pricing Models

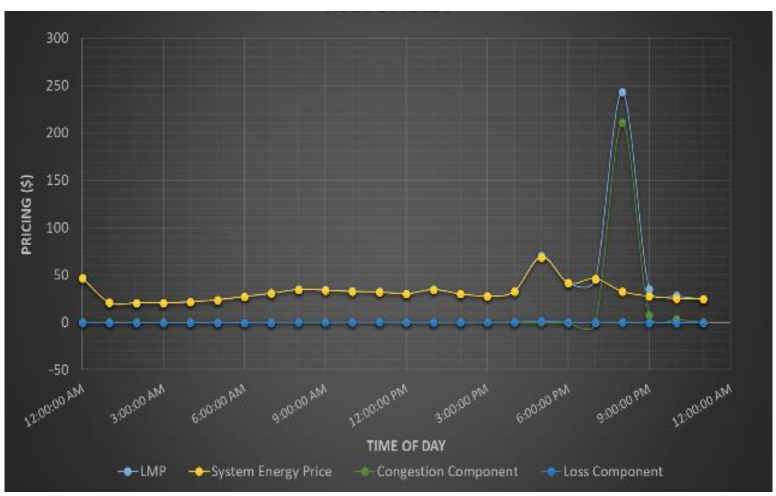
2.1 Locational Marginal Pricing

The biggest strain current grid infrastructure faces emanates from the growing population and associated loads, resulting in congestion in electrical lines. Even if the current average demand on the grid remained the same, congestion would continue to be an obstacle in utility pricing driven by radical real-time load fluctuations throughout the day. To understand the influence congestion has on electrical systems - and consequently electricity pricing - Locational Marginal Pricing (LMP) must first be understood.

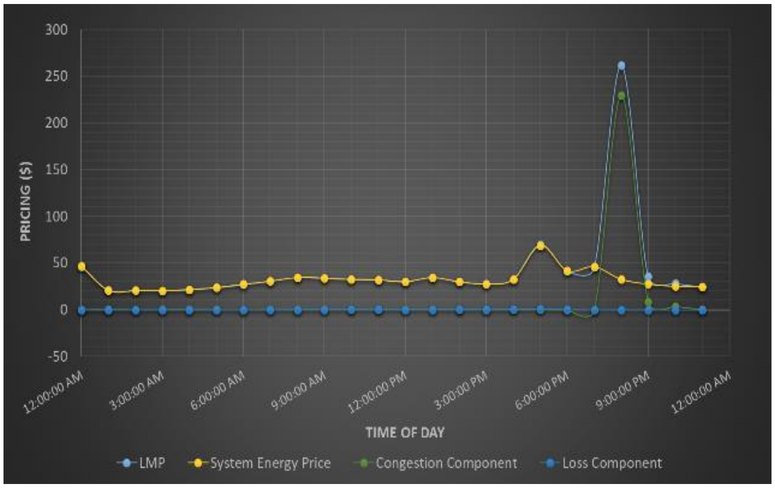
Three components make up the LMP: the system energy price, the congestion component and the loss component. The system energy cost is the set energy price for all nodes in the ISO territory per hour; in other words, it is the ideal electrical cost if no losses occurred in the system. It is determined through the combination of power plant bidding curves discussed in the previous chapter for each market hour. The maximum price that has to be paid to any singular power plant in the bid becomes the overall system baseline price. There are the two loss components, one due to electrical congestion - specifically during peak demand periods - and the other due to losses in long distance transmission.

2.1.1 Nodal breakdown

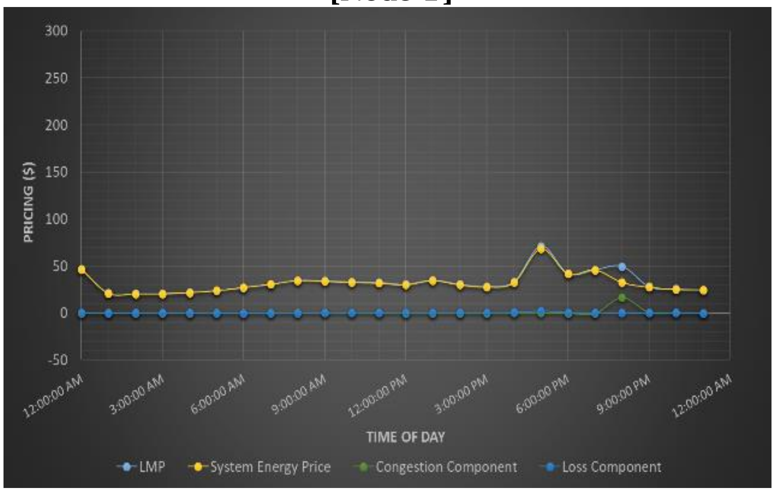
Firstly, the Pennsylvania–New Jersey–Maryland Interconnection (PJM) defines a node as a "single pricing node or subset of pricing nodes where a physical injection or withdrawal is modeled and for which a Locational Marginal Price is calculated and used for financial settlements" ("PJM Date Miner"). In simpler terms, a node can be any reference point on the electrical transmission and distribution system where there is a generation or load point for pricing indications in PJM's territory. Taking a look at three arbitrary generating nodes in the PJM zone — on a typical fall workday seen in Figure 3, the peak demand occurs between the hours of 4pm and 8pm. It is important to note that for the first and second nodes, the maximum LMP and accordingly max congestion component, occur at the same time. This supports the correlation between maximum electricity demand and congestion in the lines. The third node has little fluctuation with its LMP and congestion pricing, most likely due to its location – unknown to us, however, the minimal effect of transmission loss is still present.



[Node X]



[Node Y]



[Node Z]

Figure 3: PJM Locational Marginal Pricing Breakdown for a Given Day in the Fall of 2018

It is also important to note the wide range in congestion pricing components throughout all nodes in PJM's territory on this explored day. There is roughly a \$200/MWh difference between the maximum and minimum congestion pricing components that day while less than a \$1/MWh variation in the loss component. The congestion component has a much stronger influence on the overall LMP in comparison with its accompanying loss factor. Therefore, the conclusion can be drawn that since demand is rising each year, and peak congestion occurs during peak demand periods, it can be inferred that either congestion is increasing at nodes with increased demand and limited capacity or more areas of congestion are appearing throughout the grid in its entirety.

2.2 Congestion Pricing

2.2.1 Brief Look at Various Models

Congestion pricing can be determined in a myriad of ways with each ISO utilizing their preferred method, meaning there is no uniformly implemented system across the country. Some of the congestion pricing analyses that have been in circulation are:

- Average Participation Factors
- Congestion Revenues
- Uplift Charges

The Average Participation Factors method relies on the flow of the electricity in the network – specifically how the flow leaves each generator and runs to each load. It relies on the proportional sharing principle. Using this information, the costs of generation are distributed evenly based on where the electricity flows to and what percentage of the load comes from which generator (Junqueira et al., 2007).

Let us take a look at some hypothetical example. This system has two Areas, A and B, and each have a load and a singular power plant, Generators A and B. Each generator has its own bidding curve where it prices the electricity based on the number of megawatts it must produce. Area A has a load of 24MW while Area B has a load of 30MW, giving an overall system load of 54MW. Generator A can provide electricity according to its bidding curve at the shown price while

Generator B has its own curve and pricing. There is a transmission line connecting Areas A and B which allows power to flow from one side to the other to satisfy the load or get the cheapest electricity. In an unconstrained model, unlimited electricity can flow between the two areas; in a constrained model, only a limited amount of electricity can flow from Area A to B and vice versa.

The Congestion Revenues, or congestion charge, method looks at the cost curve for two separate generators. Congestion revenue is the difference between what the loads at one area pay versus what the generator at that one area is paid (Lesieutre & Eto, 2003). The congestion revenue is then collected by the local ISO and redistributed back into the system as the ISO deems appropriate. Generally, the revenues "are allocated to owners of the Congestion Revenue Rights (CRRs) for the congested transmission path between areas" (Lesieutre & Eto, 2003). Figure 4 shows how the congestion revenue is found graphically using the aforementioned scenario.

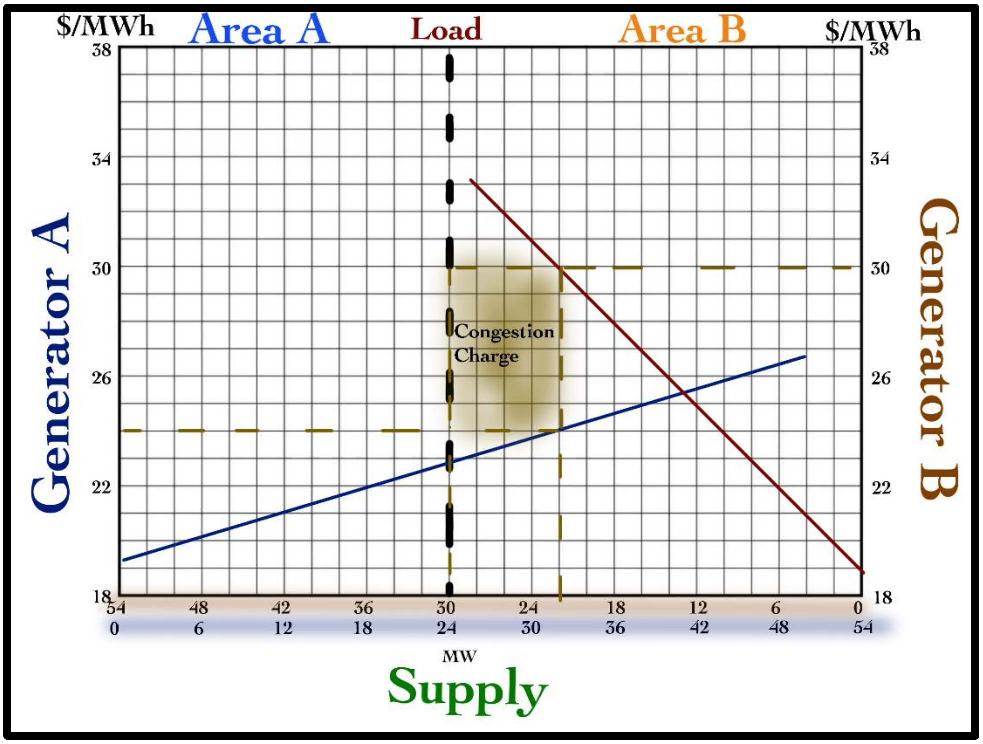


Figure 4: Congestion Revenues Diagram

In the case considered, without congestion, both generators and consumers would see a rate of about $25.50/MW with Generator B, right, supplying 13MW and Generator A, left, supplying 41MW with even payments from the loads to the consumers – where the two bidding curves intersect. In the congested scenario an 8MW restriction is place on the transmission line from Area A to B, thus Generator A can only supply 32MW and the remaining 22 must be supplied by Generator B. The 30MW load at B pays the B generator rate of $30/MW while the 24MW load at A pays the A generator rate of $24/MW for a total consumer payment of $1,476. However, Generator B is only paid for 22MW of generation at the $30/MW rate while Generator A is paid for 32MW of generation at the $24/MW rate for a total payment of $1,428. The difference of $48 between the paid and payments is collected by the ISO as the congestion charge. Figure 4A expands upon Figure 4 for further description.

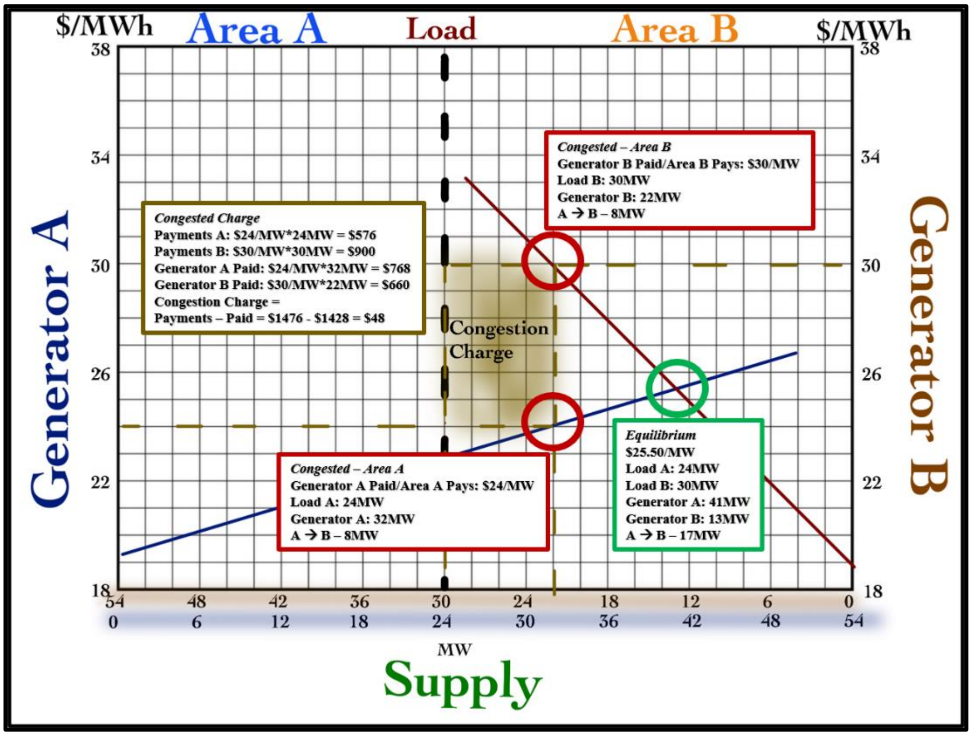


Figure 4A: Congestion Revenues Diagram Expanded

The Uplift method shares the marginal extra costs caused by congestion amongst all loads (Lesieutre & Eto, 2003). Figure 5 shows the same system as above, but with Uplift as the congestion pricing mechanism. Again, due to similarly constrained wires, Generator B is required to supply an additional 9MW than the unconstrained model; the additional cost associated with those 9MW is the shaded area along the pricing curve, about $20.25. Uncongested, all 54MW of load pay $25.50/MW. However, with the uplift charge, the additional $20.25 is shared evenly by the load thus adding $20.25/54MW = $0.375/MW to the price. The uplift congested price becomes $25.875/MW for all loads. Generator A provides 32MW and receives 32MW at this rate while Generator B receives the remainder.

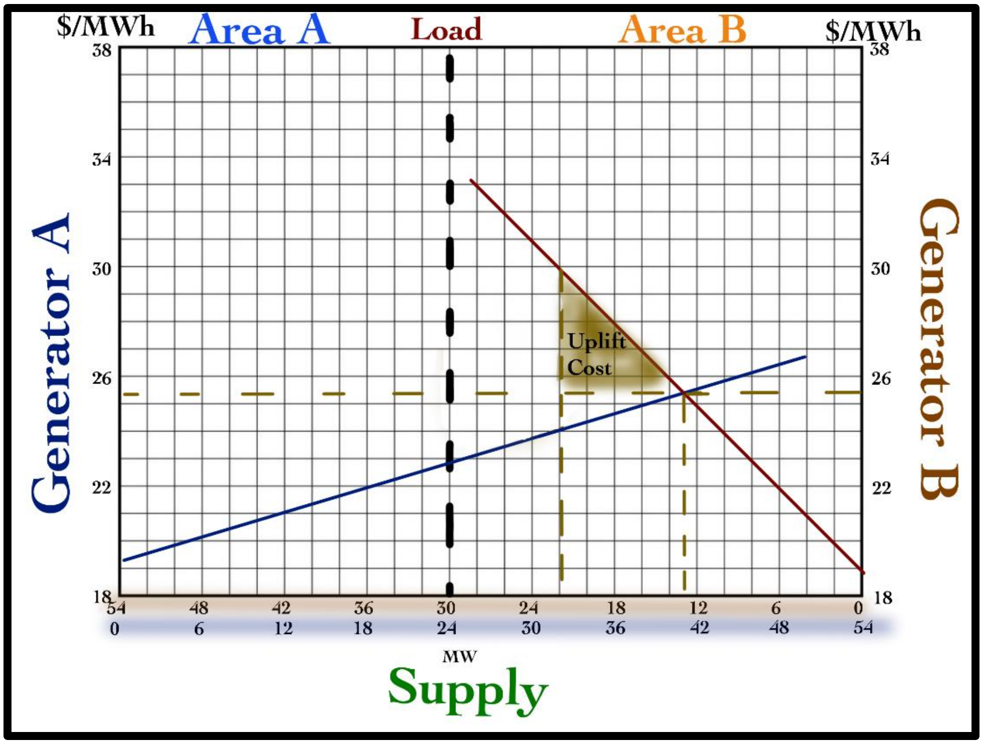


Figure 5: Uplift Diagram

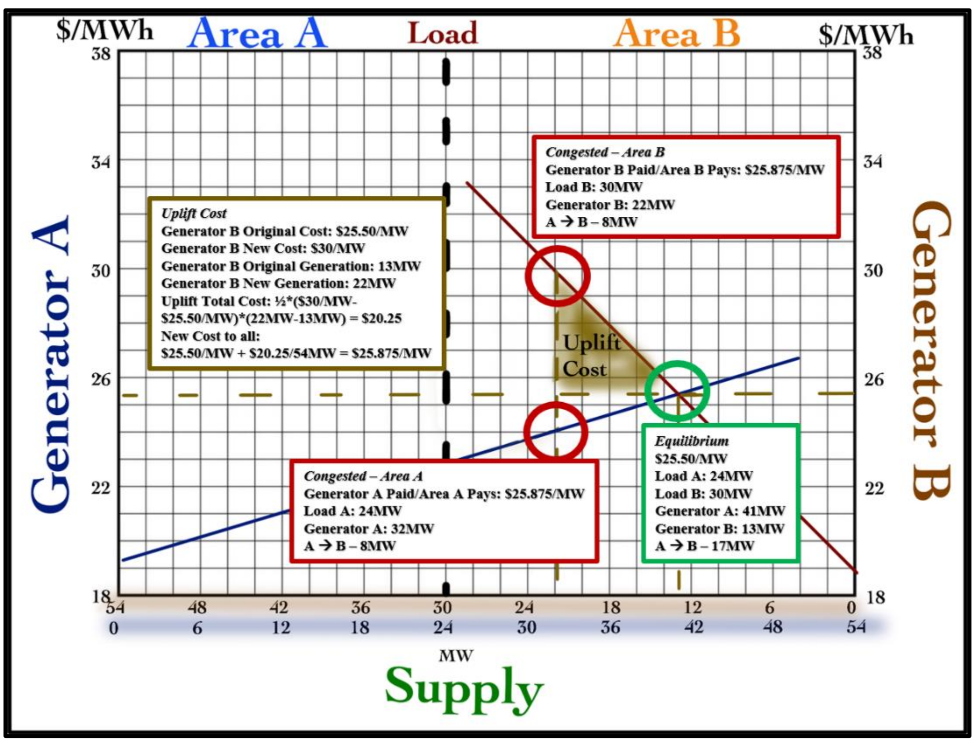


Figure 5A: Uplift Diagram Expanded

2.2.2 Proposed Model

The model proposed in our research will be called the Day Ahead Auction Principle. This model utilizes similar generation curve patterns to the Congestion and Uplift methods; however, our model follows the concept of the highest bidder. The equations below, incorporating the Lagrange Multiplier, help define the model. Lagrange multiplier was used for this analysis because the goal is to minimize the Total Cost function C_T while fulfilling the total load T. The need for minimization made Lagrange multiplier the easiest choice for all calculations.

$$F(x, y, L) = Ax^2 + By^2 - L * (x + y - T) \quad [1]$$

$$C_A = Ax^2 \quad [2] \qquad C_B = By^2 \quad [3] \qquad C_T = Ax^2 + By^2 \quad [4]$$

$$F_x = 2Ax - L \quad [5] \qquad F_y = 2By - L \quad [6] \qquad F_L = x + y - T \quad [7]$$

x = Megawatts for Generator A *T = Total Megawatts*

y = Megawatts for Generator B *C = Cost ($)*

L = Lagrange Multiplier *F_i = Derivative of F with respect to i*

A = Generator A curve multiplier *B = Generator B curve multiplier*

GC = Cost per megawatt of generation ($/MW)

$$\begin{bmatrix} 2A & 0 & 1 \\ 0 & 2B & 1 \\ 1 & 1 & 0 \end{bmatrix} \begin{bmatrix} x \\ y \\ L \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ T \end{bmatrix}$$

$$GC_A = {}^{C_A}\!/_{x} \quad [8] \qquad GC_B = {}^{C_B}\!/_{y} \quad [9]$$

With no congestion, the Lagrange Multiplier is used to determine the equilibrium pricing – or the point where both generators provide equal cost per megawatt. The calculated x and y variables define the megawatts from each generator that lead to that equilibrium price. With congestion – meaning one of the generators cannot produce as much as equilibrium and the second generator must provide the missing power – the new pricing is the higher cost per megawatt of generation from the ramping up generator. Therefore, during congested periods all generators are paid the higher price and all consumers or loads must pay that higher price. The congestion charge is the difference in total cost between the equilibrium point pricing and the congested pricing.

Figure 6 and the equations below demonstrate this where Generator A is congested and limited to below its equilibrium generation amount and Generator B has to accommodate for this with more expensive electricity.

$$Congestion\ Cost = CC_T - C_T \quad [10] \qquad CC_T = GC_B * x + GC_B * y \quad [11]$$

$$\%\ Congestion = {Congestion\ Cost}/{CC_T} \quad [12]$$

$CC_T = Congested\ Total\ Cost$

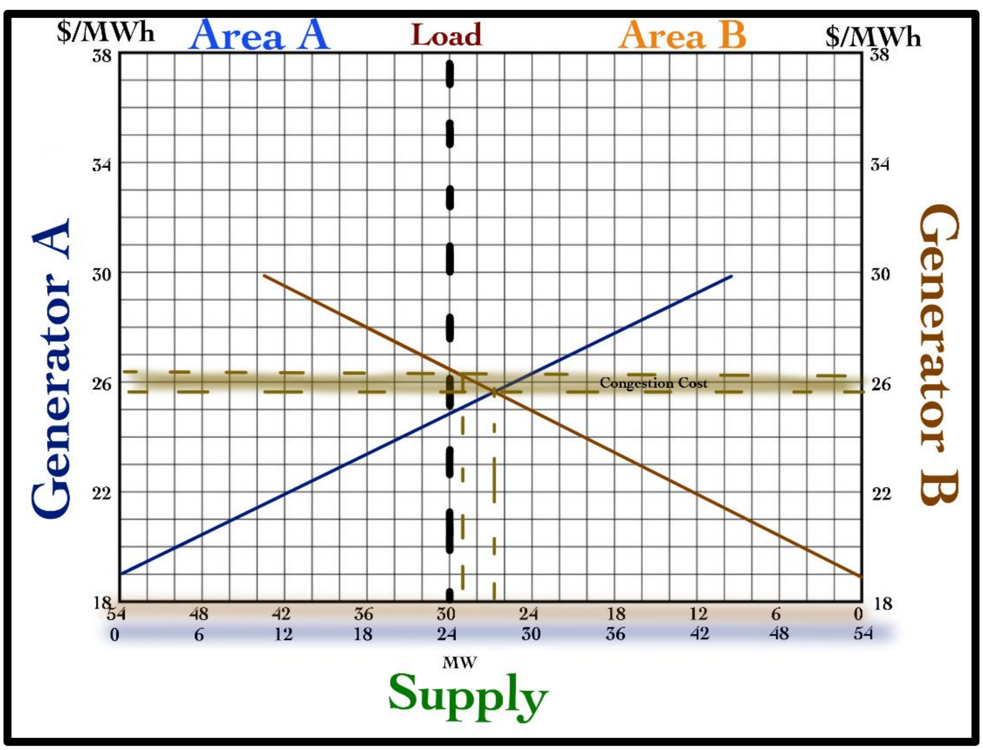


Figure 6: Day Ahead Auction Principle Diagram

In the graph above, the equilibrium price is about \$25.50/MW, with both Generators A and B providing 27MW each, in uncongested conditions. In the congested scenario, Generator A can only provide 25MW while Generator B has to make an additional 2MW. This drives B's price up to about \$26.25/MW for the whole 54MW load. That would imply about a \$0.75/MW congestion charge in the pricing for both areas or roughly \$40.50 in congestion costs and 3% congestion pricing. An expanded Figure 5A expands upon Figure 5 for more detailed graphing.

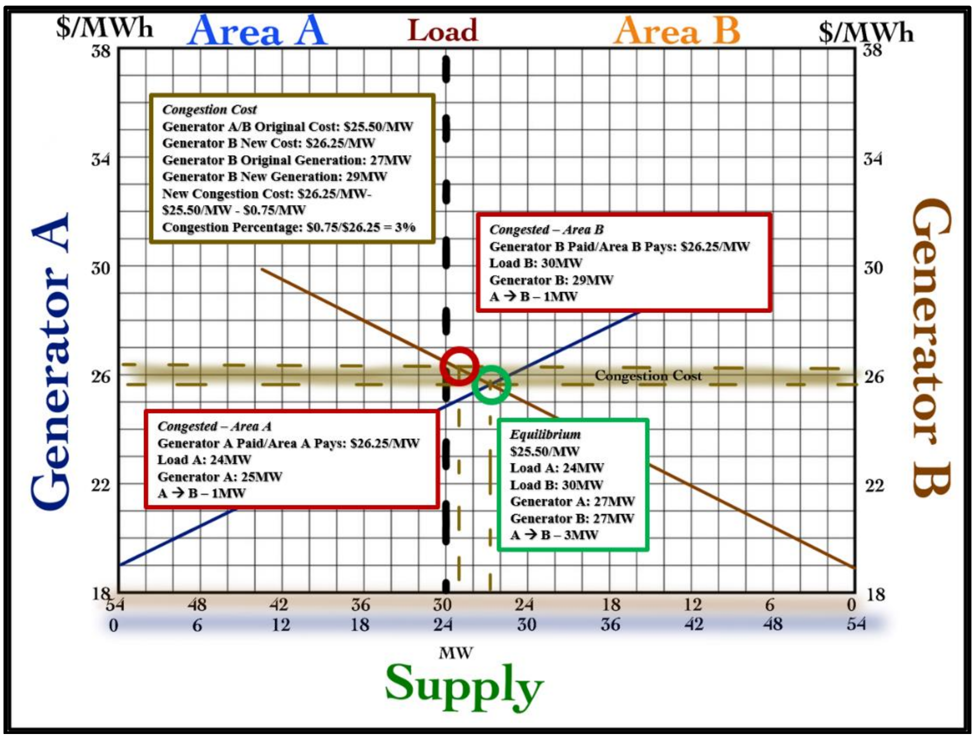


Figure 6A: Day Ahead Auction Principle Diagram Expanded

2.2.3 Distributed energy resources (DER) and congestion

When correctly implemented, distributed generation systems allow us to delay expensive transmission and distribution upgrades that would normally be necessary to expand the existing centralized grid network (Chiradeja, 2005). It is possible that if DER installation is strongly successful, it could largely replace an upgraded transmission system. The energy grid must adjust to this era shift and look towards methods of decentralizing control and management so that it takes advantage of the inevitable DER grid structure rather than continuing to treat it as a further congestion-related strain on the grid.

Chapter 3

The Site and Data Collection

3.1 The Sample Case

To better model how additional generation could potentially benefit microgrids, a sample system was used. Data was readily available for the Rutgers Busch and Livingston Microgrid, as well as access to the operational facilities. This made the Rutgers Microgrid an ideal sample case for modeling.

The Rutgers Busch and Livingston Microgrid, part of Rutgers, New Brunswick Campuses, consists of three main components. A 15MW CHP plant containing three 5MW turbines – which is currently undergoing an internal hardware upgrade – and 9.4MW of solar comprised of an 8MW solar canopy installation, and a 1.4MW solar farm ("Strategic Planning Energy," n.d.). The cogeneration uses three 5MW Solar Turbines, Model Tuarus 60-6500.

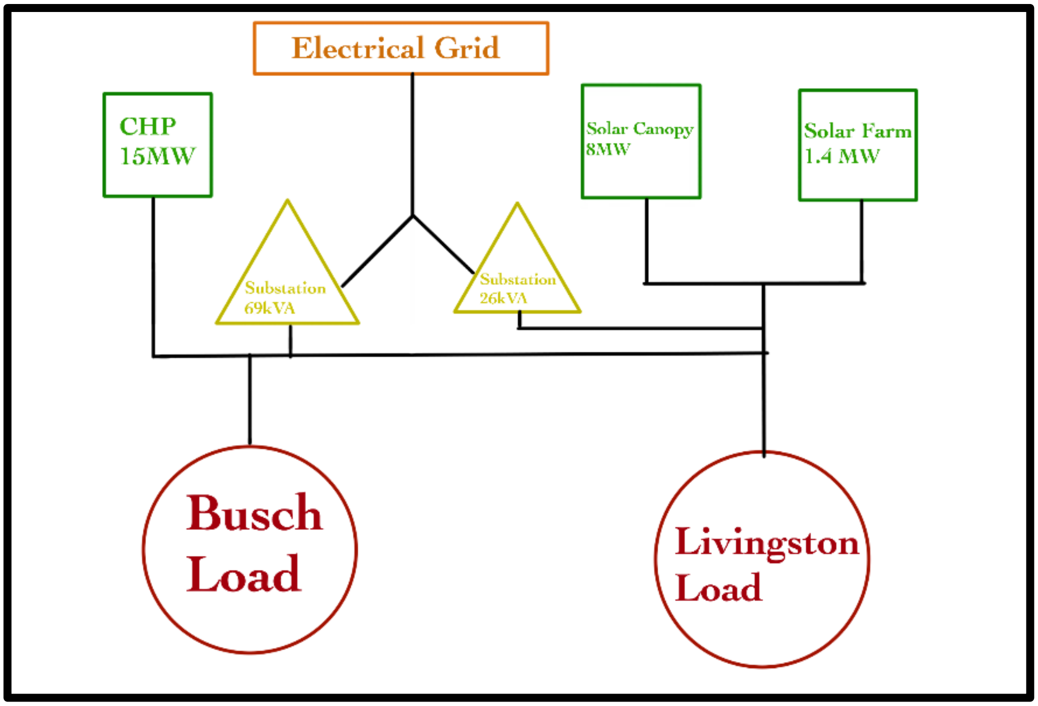


Figure 7: Rutgers Busch and Livingston Microgrid Setup

These systems combine to provide on average about 55-60% of the necessary power for the microgrid based on their current operation. The microgrid also contains a substation at 69kVA as well as a secondary substation operating at 26kVA. These substations allow additional power from the grid to be imported into the Rutgers microgrid to supply the remaining 40-45% of the needed power. According to plant personnel – and data confirmed – the CHP plant only runs at full capacity for less than 50% of the year. Due to an agreement with their energy provider, PSEG, Rutgers is required to purchase a minimum of 1MW at any given time. Figure 8 shows how the Rutgers microgrid load fluctuates over time, averaged every ten data points, which is equivalent to every 10 hours, according to data from the Rutgers Icetec system. The microgrid experienced a minimum load of about 15MW and am maximum load of 35MW throughout the observed year. The winter months experience an overall lower load while the summer months have a significantly larger load. This can be strongly attributed to the need for high-powered air-conditioning systems in the summer months which drastically increase the load.

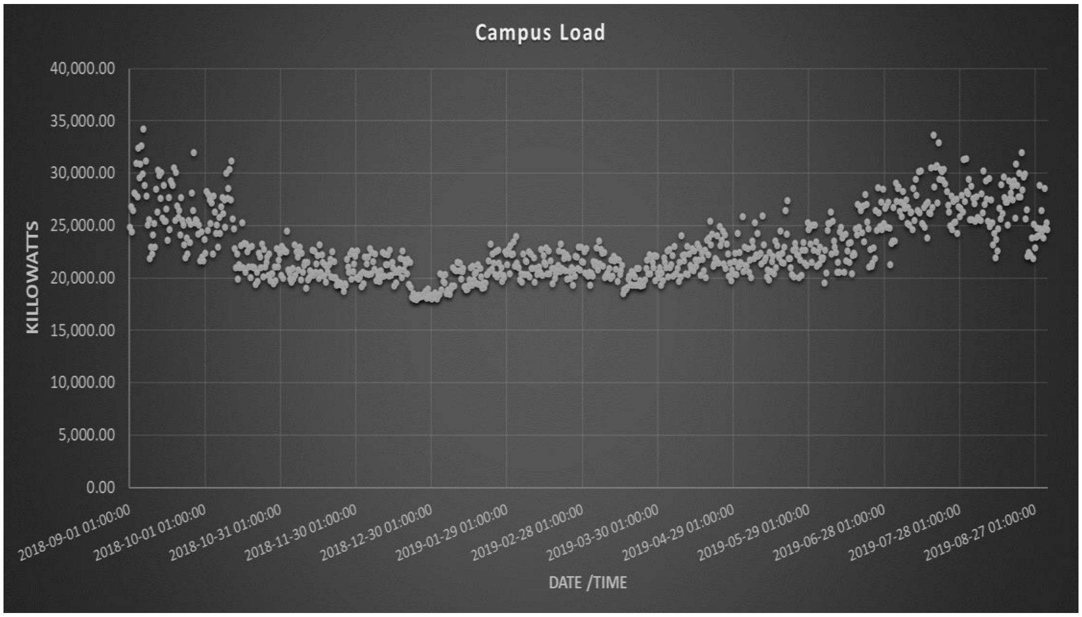


Figure 8: Rutgers Microgrid Load Over Time

Figures 9 and 10 show the daily load fluctuations for a typical school day in early October compared to a non-school day in mid-June. Despite fewer students being present during the non-school period, the load follows a nearly identical pattern.

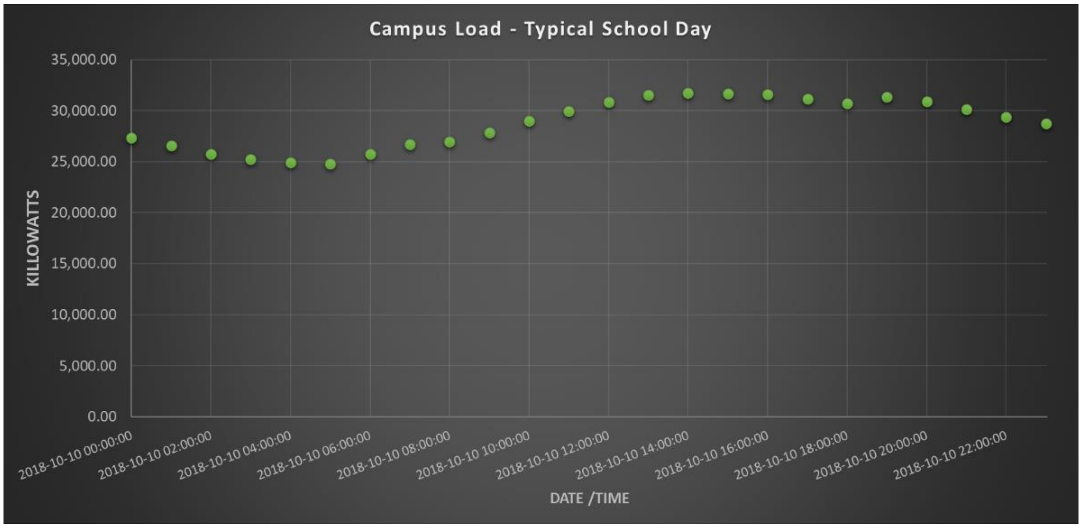


Figure 9: Campus Load During a Typical School Day

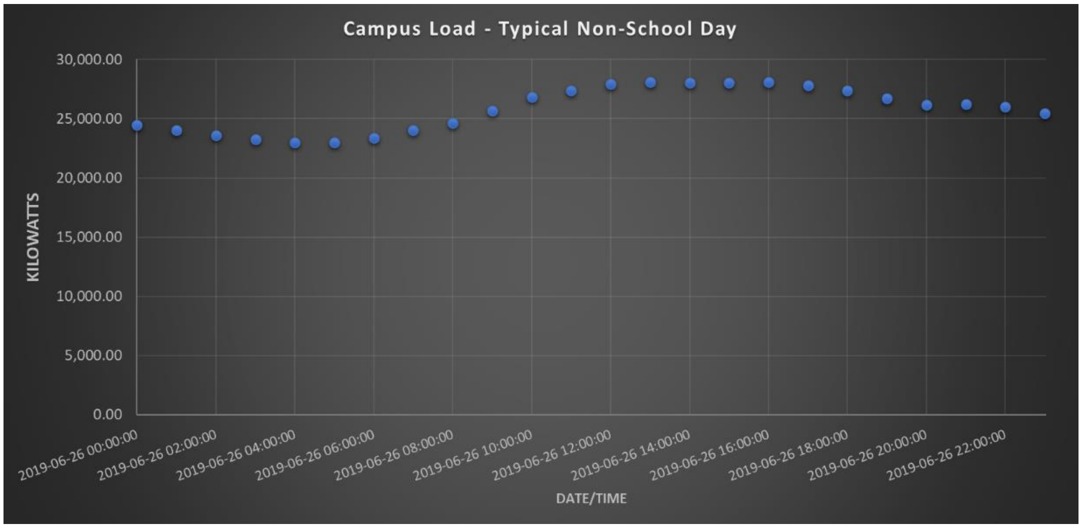


Figure 10: Campus Load During a Typical Non-School Day

When comparing a whole week during a school semester versus during the summer session, with 0 being the first hour of the week, Sunday at midnight and 168 being the final hour of the week, Saturday at 11:00pm. The same pattern of load variations is present throughout the weekdays. The load is slightly larger during the school period, but the same flow is apparent. The most distinct variation is in the weekend period. The non-school time weekend load remains larger while the school-time weekend load decreases as the weekend approaches.

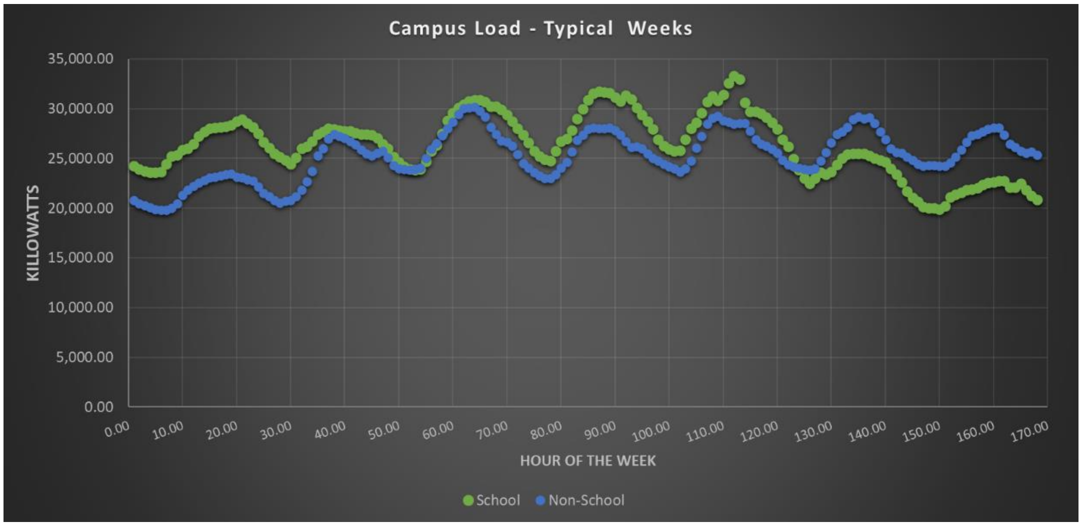


Figure 11: Campus Load Comparing School in Session (Green) vs. Not in Session (Blue)

With Rutgers making a push towards a more ecofriendly and sustainable campus (Brightman 2018), the question is – why aren't we producing more in-house power to promote higher efficiency energy generation as well as seeking out opportunities for exporting excess energy production.

Figure 12: Rutgers Cogeneration Plant

3.2 Data Collection

To analyze the Rutgers microgrid system in its entirety, the cooperation of a combination of separate entities is required. With permission from the Rutgers Facilities Maintenance & Operations Utilities as well as the Cogeneration plant personnel, their personal data collection center was utilized. The entirety of the CHP and solar operation data was pulled from the Rutgers data collection and operation software provided by a third-party entity – Icetec. Icetec monitors the turbine operation as well as the factors that determine whether it should be running – such as the natural gas pricing and spark spread as well as the LMP for Rutgers' local PJM zone. The spark spread is the difference in pricing between the cost to generate and the market price or LMP. It advises the generator as to whether it should purchase power or generate its own based on the pricing difference. However, Icetec has no direct control over the operations directly; they only make suggestions based on these influencing factors. It is up to the onsite plant operators to determine the best course of action for all real-time scenarios. This is mainly decided by cogeneration plant personnel through monitoring Icetec's live operations interface shown in Figure 13.

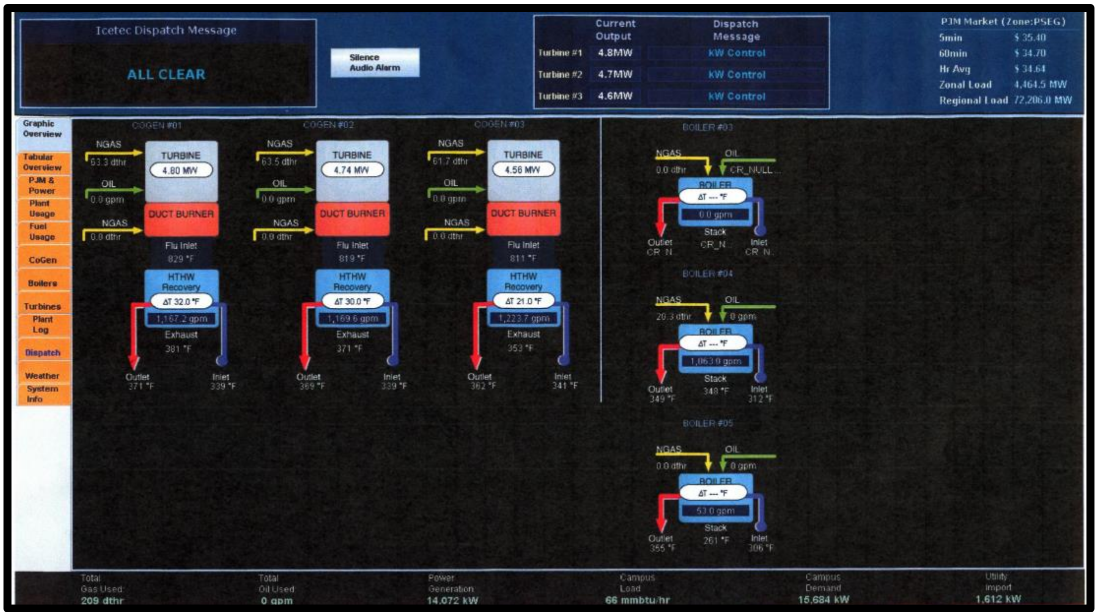


Figure 13: Icetec Live Monitoring Screen

On the trends side of Icetec, a myriad of different data pieces are collected for Rutgers use and records. Operational data for the boilers, duct burners, turbines, solar installations, heated hot water recovery system and carbon emissions are just some of the components that data is collected for. There are also data loggers which record reserve-water tank levels, as natural gas and oil usage, chiller operational data, outdoor ambient temperature, campus load and utility kilowatt input. The natural gas and oil usage values are visible in Figure 13 while the other recorded data is spread throughout the various tabs seen on the left. Figure 14 expands upon some of the data sets available through the Icetec software.

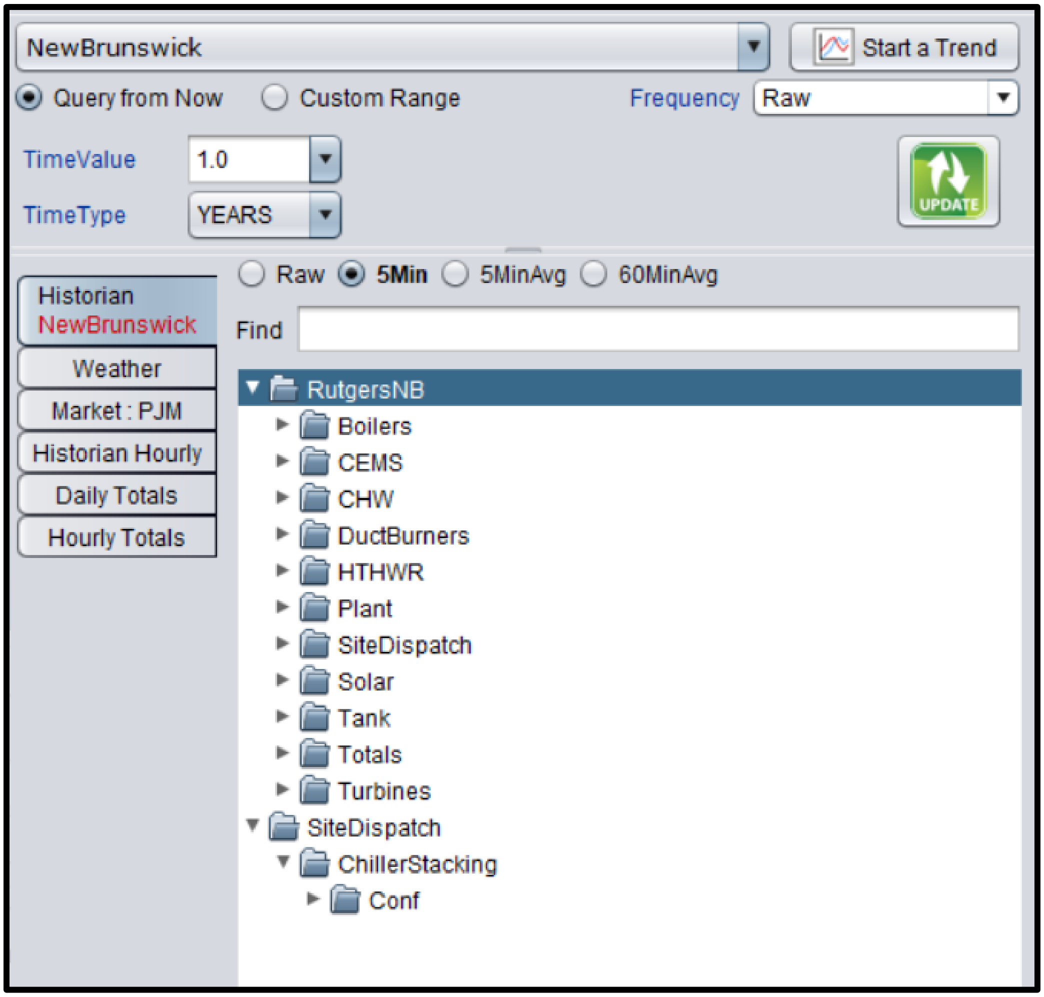


Figure 14: Icetec Software Insight

Data Header	**Data Subset Samples**
Boilers	• Gas/Oil flow • Stack temperature • Outlet temperature
CEMS – Carbon Emissions	• Carbon Monoxide emissions • Nitrous Oxide emissions • Oxygen count
Duct Burners	• Gas flow • Oil flow
Solar	• Total canopy system kilowatts • Total ground system kilowatts
Turbines	• Gas/Oil flow • Kilowatt generation

Table 1: Icetec Software Insight Description

The Icetec software allows for custom data ranges as well as time-interval based averages to be graphically displayed with ease. There was also the ability for trends to be viewed for each data selected which could then be saved in the system for later review and reference. There are two different formats for graphing which are both shown below. For example, Figure 15 uses the basic trend graphs to show the oil and gas flow into the duct burners over a whole year. According to the data, the duct burners are used very sparingly by the cogeneration plant. This was attributed to high-risk tubing failure connected to the duct burners which could cause a plant failure and shutdown. Meanwhile, Figure 16 uses the interactive trending tool to show Boiler oil and gas flow. The oldest data recorded on the system is from April 26, 2016 at 1:00am. The data ranges utilized in this research did not extend past 2018, thus there were no problems with lack of data collection.

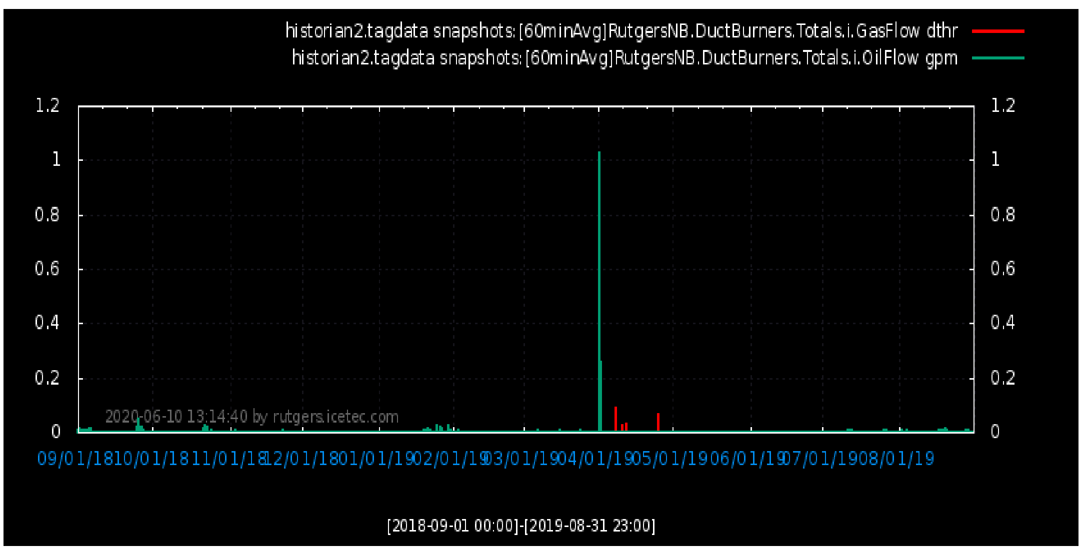


Figure 15: Duct Burner Operation

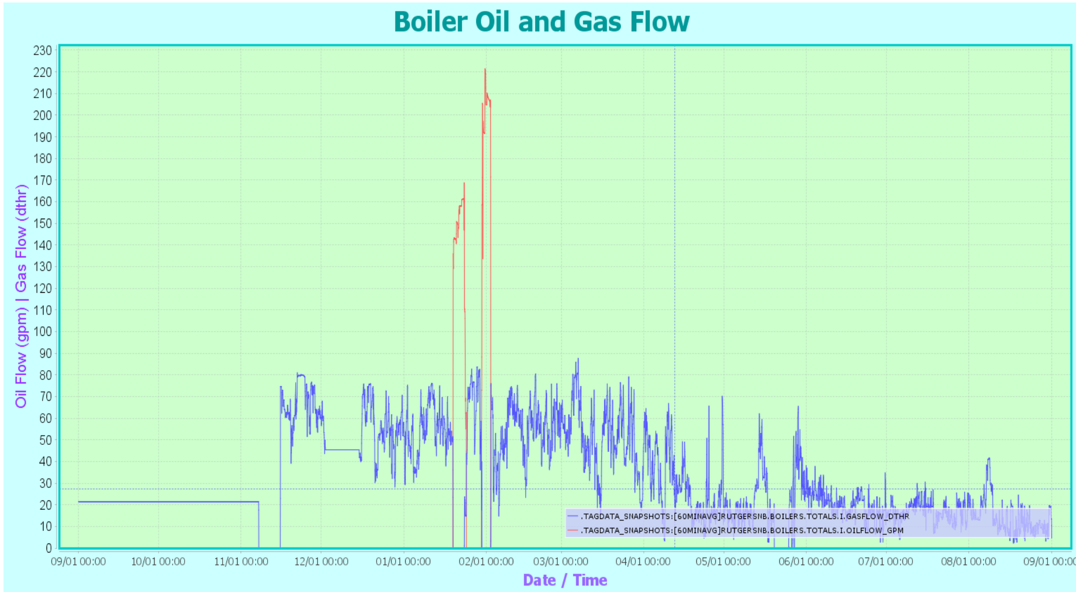


Figure 16: Boiler Operational Data

Through Icetec, PJM market data is collected as well, however the data only consists of zonal averages for PSEG's coverage and overall PJM market averages. There is no specific nodal data due to PJM's restrictions. However, market averages do not always represent individual stresses at specific points in the grid. Therefore, nodal data was pulled from the other main source of data collection, PJM and its Data Miner.

PJM's Data Miner is a vast collection of historical data pertaining to the PJM grid area. Although the data is public, explicit permission needs to be received from PJM in order to use the data in any published work. Permission was received from PJM for all data in this thesis. The Data Miner consists of the following data categories:

- Ancillary Services
- Bid and Offer Data
- Constraints
- Credit
- Financial Transmission Rights
- Generation
- Imports and Exports
- LMP Model
- Load
- Load Forecast
- Locational Marginal Prices
- Losses
- Reference Data
- Retired
- Settlements
- System Information
- Uplift

From these categories, trends can be observed from the data, such as the generation by fuel type over the course of a week in June of 2019 shown in Figure 17. Or the predicted load in ComEd – Commonwealth Edison Co. – territory for that same week in June given in Figure 18.

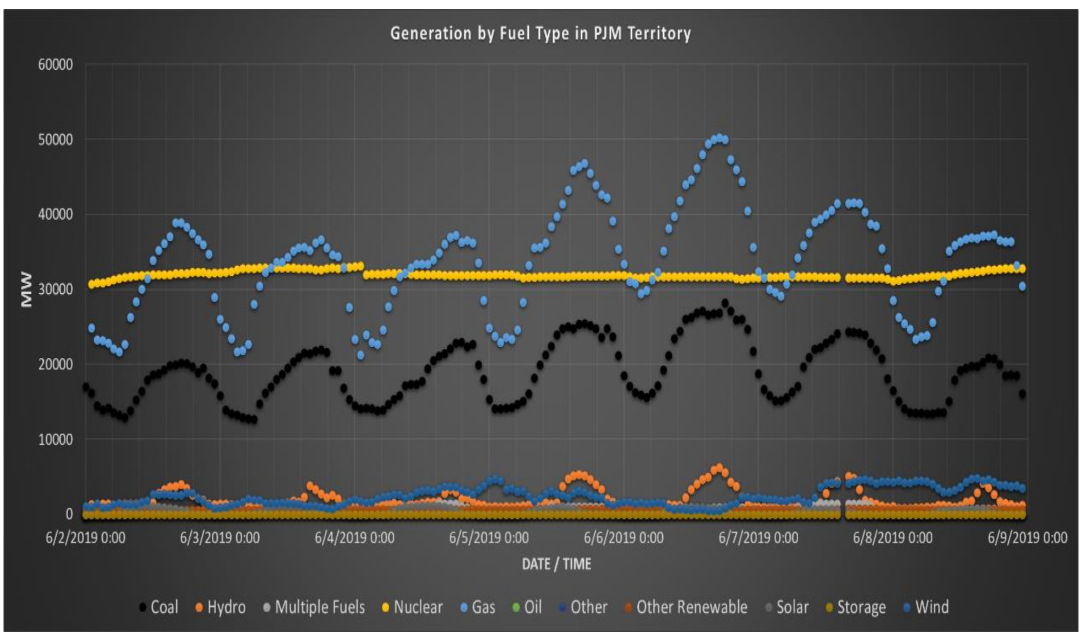


Figure 17: Generation by Fuel Type in PJM

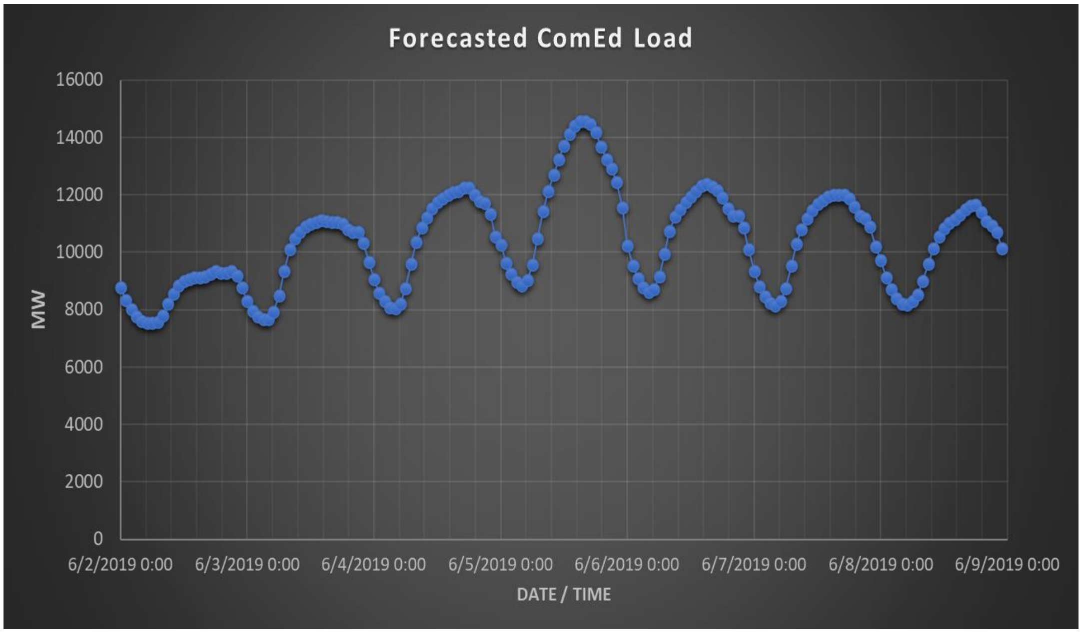


Figure 18: ComEd's Predicted Load

Although a good portion of PJM data is open to the public, there still is some that is not accessible. Data that is not available through the PJM Data Miner is below:

- Older History (prior to 1/1/16)
- Individual Generator Output
- Nodal Load
- Capacity Commitments
- Individual Generator Outages
- Individual Generator Offers
- Locational Data
- Shape Files

The most significant piece of omitted data pertaining to our research is lack of specific nodal information. Locational and load data for any given node is not available to the public. For this reason, a selection of randomized nodes was utilized for all analysis to provide various possible models that may represent the Rutgers microgrid node depending on its location.

The data used from PJM for the majority of this analysis was obtained from the Real-Time Hourly LMP data set. LMP pricing and its individual loss components were used for price comparisons and cost estimations. As mentioned, the exact node for the Rutgers University substation could not be shared with us due to confidentiality reasons, therefore a selection of arbitrary nodes in PJM's PSEG zone were used in its place. Each node has its own congestion pricing and transmission loss components based on its precise location, thus each having their own effect on the calculations.

3.2.1 Data ranges and intervals

To keep data comparison reliable throughout different sources of data collection, a consistent date range and data interval were used. The hourly average was used for each variable in our calculations. The date range focused on was September 1, 2018 at 0:00 to August 31, 2019 at 23:00. Although there are 8760 hours in a year, for Icetec, there are fewer than 8760 data points due to a few gaps in their data collection. All data sets were missing one hour due to daylight savings. During the spring daylight savings, because the clock goes from 1:59am to 3:00am, there is a 2:00am data point missing on March 10, 2019. This should have been compensated by the fall daylight savings where 1:00am to 1:59am occurs twice, however instead of duplicating the hour, the original time was overridden by the second 1:00am data points. Thus, there are only 8759 hourly datapoints throughout all Icetec data. All hours were carefully analyzed to ensure that all data sets matched across the board for each category and omitted hours were consistent for all analyses.

Chapter 4

Methodology

4.1 Case Assumptions

Both cases mentioned in Section 1.4 focus on the installation of new generation. They assume the installation of new, high end turbines with up to 45% efficiency. The cost of these turbines involves capital costs per megawatt of installation as well as annual fixed Operations and Maintenance fees per kilowatt-year. For the purpose of this research, it was estimated the turbines would cost about $700,000/MW with a 25-year capital coverage and an operational estimated cost of $10/kW-year.

To analyze the effects of incorporating into a microgrid like Case 2, the Rutgers microgrid was used as a sample with its own set of assumptions. The first assumption is the ability and permission for Rutgers Busch and Livingston microgrid to export excess generation back into the grid. This entails that PSEG allows for sale either back to them as a whole or to individual separate entities through the use of their current transmission and distribution lines. It was also assumed that all three turbines used natural gas as a fuel source 100% of the time. Oil was used on occasion by request of PSEG due to natural gas shortages, however, usage hours are unpredictable and far and few between. Therefore, it was chosen to omit the few hours that does occur. The final assumption is that all data utilized from the data sources – Icetec and PJM – is fully reliable and accurate to the best of its ability.

4.2 Case 2 Pre-expansion Site Strategy

Prior to looking at opportunities for expansion in Case 2, the current setup of the Rutgers Buch and Livingston Campus microgrid was evaluated. Currently, the cogeneration plant only runs at partial capacity often, in part due to the 1MW contract with PSEG. A pre-analysis was performed to determine the cogeneration capacity when fully loaded to produce maximum generation and without the regulations of the PSEG contract.

4.2.1 Breakdown of the pre-analysis

The first part of this pre-analysis involved the creation of a prediction curve for the performance of the turbines based on historical natural gas usage. From there, an average efficiency for the turbines was calculated. The efficiency was then used for predicting natural gas usage at 100% load. Lastly, opportunities for economic benefit – the sale of excess electrical generation – were obtained based on the current machinery present at the cogeneration plant, in combination with the generated solar.

4.2.2 Predicting turbine efficiency

Pulling operational turbine data from Icetec showed that the turbines rarely operated at maximum output; on average they operated at about 73% of their full 15MW rated capacity. To predict natural gas usage while fully loaded, the historical natural gas information was used. Implementing the efficiency equation below, the turbine efficiency was calculated for each hour of the designated year, as show in Equation 13.

$$\eta = \frac{kilowatts\ out}{dekatherms\ natural\ gas\ in * \frac{293\ kilowatts}{dekatherm}} * 100\% \quad [13]$$

4.2.3 Modeling natural gas usage

From there, the average efficiency found was used to calculate natural gas usage while fully loaded. This natural gas usage allowed for the calculation of cost for generating electricity through the cogeneration plant. Using Equation 14, a cost per megawatt of generation was found. However, because this is a cogeneration plant, only 2/3 of the natural gas was calculated as part of the generating cost. This is because roughly 1/3 of the natural gas costs go towards the heat that is used in other processes and not towards the electrical generation. All variables are defined in Tables 2 and 3 in Section 4.3.

$$CGC = \frac{\left(\frac{N_{CG}}{\eta}\right) * \frac{2}{3} * 3.412 \frac{dtherms}{MW} * NGP}{N_{CG}} \quad [14]$$

4.2.4 Opportunities with current microgrid infrastructure

After determining the cost to generate, the number of hours where excess generation could be produced based on fully loaded turbines was evaluated in comparison to the campus load. It was then determined if there was room in the market for electricity above our operational cost.

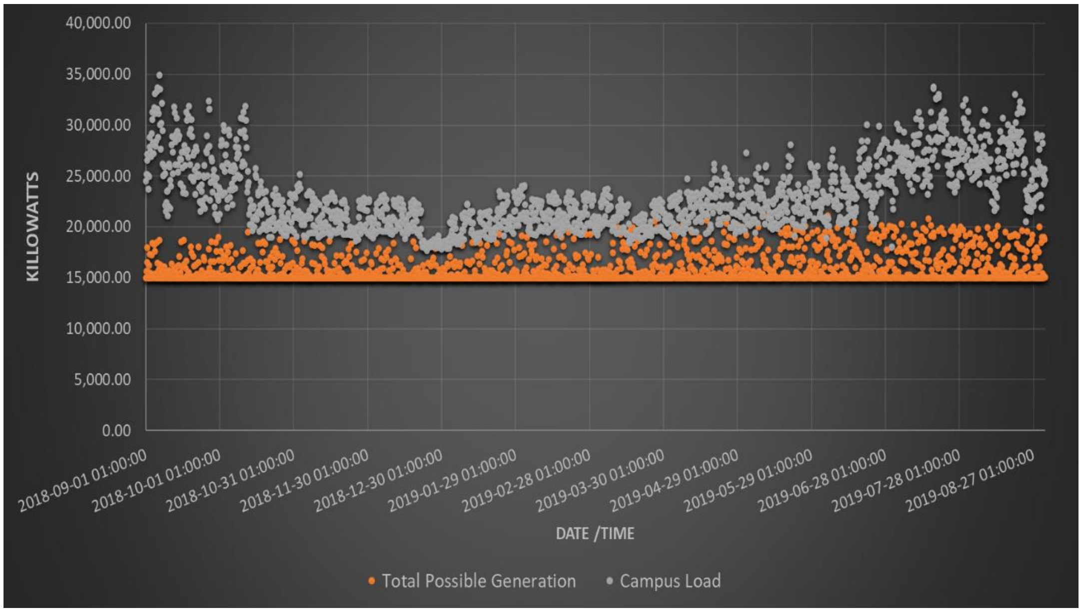


Figure 19: Campus Load versus Generation

Figure 19 shows the campus load throughout the year, averaged every five hours. There were fewer than forty instances where the total generating capacity is greater than the campus load. It was observed that the cogeneration plant in combination with the solar was too undersized most hours for the campus load imposed by both Busch and Livingston Campus because less than half a percent of the hours had opportunities for excess generation. Although this is the case, according to plant personnel, the turbines are curtailed some hours due to the 1MW that must always be imported from PSEG. If there is a risk of overlapping with the 1MW import due to uncertainty in the predicted campus load, the turbines are curtailed for security. Thus, for this research, the 1MW was assumed to be overridden and only new generation incorporation was considered for the remainder of the analysis.

4.3 Two Cases Equations

The generation expansion model was broken into five steps with two distinct cases – Case 1 and Case 2 – and three distinct nodes inside PSEG's territory – Nodes A, B and C. The five steps are broken up to allow for easier understanding and analysis of the model. As mentioned previously, the grid node identities are kept anonymous for security reasons, however the zone information is still available. With that, a load node inside PSEG's territory was selected as a potential to "sell" the excess generation to. The real time hourly market pricing was utilized for this purpose. The first case is designed to mimic a standalone power plant. It evaluates the impact of an individual megawatt being generated and sold into the grid at some node and the revenue associated with selling at the market price. The analysis performed on the second case is very similar to that of the first case; however, it supplies power to satisfy the Rutgers Microgrid load first and then sells the excess generation into the grid. Case 2 is designed firstly with the idea of creating a self-sustaining campus in mind and with economics as a secondary thought while Case 1 is solely focused on improved economics.

If the market price for a given hour was above the cost of generation per kilowatt-hour, it was deemed a viable economic hour.

All possible hours of the year for which there were data were evaluated in search of viable economics. The equations in Table 2 were used to determine the selling price and net revenue associated with the sellable hours.

<table>
<tr><th colspan="2">Both Cases</th></tr>
<tr><td>$GC = \frac{TC}{N_T} = \frac{\left(\frac{N_T}{\eta}\right) * 3.412 \frac{dtherms}{MW} * NGP}{N_T}$</td><td>$LMP = SP + CP + LP$</td></tr>
<tr><td>$F_i = \frac{\left[\left(CA_T * \frac{\%\ Paid}{year} + OM\right) * N_T\right]}{8760hrs}$</td><td>$PC\ (\%) = \frac{Congestion\ Cost}{LMP} * 100$</td></tr>
<tr><th>Case 1</th><th>Case 2</th></tr>
<tr><td>$R = \sum_{i=1}^{8760} [(LMP_i - GC_i) * E_i - F_i]$</td><td>$R = \sum_{i=1}^{8760} [SL_i + CGS_i + P_i - F_i]$</td></tr>
<tr><td>$E_i = N_{T_i}$</td><td>$E_i = G_i - CL_i$</td></tr>
<tr><td rowspan="4">$R_{Ti} = \sum_{i=1}^{8760} \left\langle \left\{ LMP_i - \left[\frac{\left(\frac{N_{T_i}}{\eta}\right) * 3.412 \frac{dtherms}{MW} * NGP}{N_T} \right]_i \right\} * E_i - F_i \right\rangle$</td><td>$CGC = \frac{\left(\frac{N_{CG}}{\eta}\right) * \frac{2}{3} * 3.412 \frac{dtherms}{MW} * NGP}{N_{CG}}$</td></tr>
<tr><td>$SL_i = \sum_{i=1}^{8760} \langle \{LMP_i - GC_i\} * (N - E_i) \rangle$</td></tr>
<tr><td>$P_i = \sum_{i=1}^{8760} [(LMP_i - GC_i) * E_i]$</td></tr>
<tr><td>$CGS_i = \sum_{i=1}^{8760} [(LMP_i - CGC_i) * N_{CG}]$</td></tr>
</table>

Table 2: Equations for Expansion Analysis

Variables	
R = Revenue [$]	LMP = Locational Marginal Price [$/MWh]
GC = Generating Cost [$/MWh]	N_T = Number of MW additional turbine [MW]
E = Excess Generation [MWh]	NGP = Natural Gas Price [$/dtherm]
F = Capital & Fees [$]	TC = Total Generating Cost [$]
G = Total Generation [MWh]	CL = Campus Load [MW]
CA_T = Capital Cost per MW of turbine [$/MW]	OM = Operation & Maintenance per MW per year [$/MW-yr]
SP = System Price [$/MW]	CP = Congestion Price [$/MW]
LP = Loss Price [$/MW]	SL = Savings/Losses from Using in House [$]
P = Profit from selling [$]	PC = Percent Congestion
CGC = Cogeneration Generating Cost [$/MW]	CGS = Savings/Losses from Using Cogeneration [$]
N_{CG} = Megawatts of Cogeneration [MW]	η = Cogeneration Efficiency

Table 3: Variables of Equations for Expansion Analysis

4.4 Four Steps

The analysis was broken up into four distinct stages for clearer evaluation. Each step adds a more complex layer to the model, expanding until all aspects and calculations are covered.

4.4.1 Step 1 – The Breakeven Price for Constant Selling

The initial stage of analysis involves the most basic form of energy production and distribution. Each megawatt of electricity generated is distributed into the grid regardless of the electricity pricing. For this initial stage, only the system price is acknowledged. Step 1 is in search of the breakeven price – or the price where selling into the system price 24/7 neither profits nor loses. The natural gas price is varied to find where the Net Revenue produces exactly $0. The natural gas price found, X dollars, says that as long as the pricing stays at X dollars or lower, if the turbine is selling at all hours, no money will be lost.

4.4.2 Step 2 – The Breakeven Price for Selling Smart

Step 2 of the analysis upgrades the selling procedure of step 1 while following similar calculations. The main difference between steps 1 and 2 is that during step 2, the selling process only focuses on profitable hours. For Case 1, if the generating price is below the system price for any given hour, the turbine sells the megawatts to the grid. However, because the Rutgers Microgrid also purchases electricity from the grid at the Market Price, Phase 1 also mimics the effect of the Rutgers campus generating the megawatts themselves and consuming them in a profitable manner. The savings from self-generating during expensive electricity market hours is the same as the revenue received from selling at the market price.

Case 2 replicates nearly the same process, except it satisfies the Rutgers Microgrid load first, despite the system pricing, and then sells any excess into the grid in the more profitable method described for Case 1. The savings and losses incurred while fulfilling the Rutgers load are included in the Net Revenue from selling into the grid. Due to the Rutgers load being satisfied first and smart selling implemented secondary, the analysis for Case 2 is evaluated after 8MW input rather than 1MW input utilized for Case 1. This is because, according to Icetec data, the average import from the grid would be 7MW with the turbine setup described for Case 2. Therefore, 8MW is where smart distribution into the grid begins to be implemented like that in Case 1.

4.4.3 Step 3 – The Breakeven Price for Selling Smart with LMP

The third step of this analysis is nearly identical to the second step, except now instead of comparing the generating cost to the system price, it is compared to the LMP or Locational Marginal Pricing. Case 1 and 2 perform the same calculations with this new pricing model to find where the Net Revenue – or Net Revenue plus savings and losses as mentioned above – produce exactly $0.

4.4.4 Step 4 – The Effects on Congestion Pricing

The fourth step acknowledges the real grid-effects of incorporating new generation – or removing loads – will have on the pricing. Positive congestion pricing in the LMP implies that there is a location not too far down the line from the node that has a large power drawing load. Adding generation above that point to help supply the load will in turn lower that positive congestion pricing. Using Lagrange multipliers linear optimization, a few different instances of sudden spikes in congestion were evaluated for one of the nodes closest to Piscataway, NJ. To be considered a spike, the congestion pricing was converted to a percentage of the LMP. If there was a significant jump in percentage, the associated change in congestion pricing was utilized. The load was determined to be the average electricity usage for Piscataway, NJ provided by EERE's State and Local Energy Data. Two generators were set to supply the load with equal linear pricing curves like those in Figure 6 in section 2.2.2. The percent change in congestion pricing was compared to the megawatts change in load from a congested generator that would cause that percentage change in congestion pricing. The average was taken between the spiked impacts, therefore, each megawatt generated decreased the congestion pricing, and thus the LMP, by a set amount. Case 1 and 2 were revaluated as in Step 3 with this new effect on the pricing model.

Chapter 5

The Results

5.1 Pre-expansion Site Modeling

As mentioned in Section 4.2, the Busch Cogeneration plant runs at partial capacity often, thus a performance model had to be created to simulate how the turbines would run fully loaded all of the time.

5.1.1 Predicting turbine efficiency

The turbine generation at full capacity was modeled using Turbine #1 throughout the year. To calculate the efficiency of the turbines, historical natural gas usage and turbine generation was utilized. Five-minute interval data was compared to find the ratio of natural gas in to kilowatts out throughout the year. An average efficiency of about 25% was found. Figure 20 shows the natural gas in versus the kilowatts out averaged every 120 data points, which corresponds to every 10 hours.

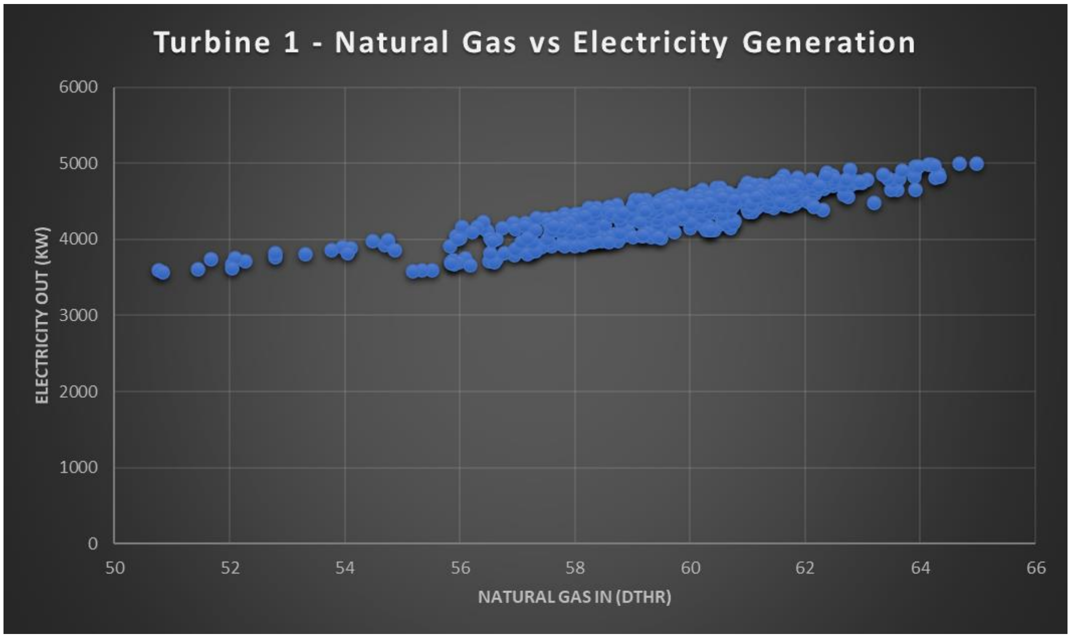


Figure 20: Turbine #1 Historical Usage and Operation

5.1.2 Modeling natural gas usage

For the purpose of this research, the turbines are modeled to be operating fully loaded. Using the efficiency found in the previous section, the natural gas consumption can be calculated. For a single 5MW turbine with an efficiency of roughly 25%, the natural gas being consumed would correspond to about 67 dekatherms. It is important to note that this does not perfectly line up to the Figure above. However, this is because an overall average system turbine efficiency was used. Once the natural gas usage was calculated, the cost to run the cogeneration turbines was found. Equation 14 can now be simplified.

$$CGC = 9.08\frac{dtherms}{MW} * NGP$$

All of the pre-analysis performed will be utilized for calculations throughout Case 2. But first, the independent operations and opportunities of Case 1 are reviewed.

5.2 Case 1 – New Generation

As mentioned, Case 1 is modeled as operating as a standalone power plant. All new generation is viewed as new input into the three examined nodes in the grid.

5.2.1 Steps 1, 2 and 3

Firstly, in order to sell 100% of the time while netting exactly $0 revenue, for Case 1, the generating cost would need to be about $24.20/MW. In other words, if this new power plant can produce electricity at about $24/MW, it will never lose money if it sells all of its generation into the grid if congestion was not a factor.

However, selling 24/7 is not always the most logical response. Strategic generating and selling of power allow for more leeway in the generating cost. If this new power plant only produced when it was opportune to do so, to never lose money, the power plant would only need to produce electricity at a cost of about $28.47/MW to avoid negative revenues – about $4.20/MW more than the constant selling technique. Varying the nodes between Nodes A, B and C will produce the same outcome for both steps because, as mentioned, only the system price is reviewed.

Step 2 is significant because this price demonstrates that if the generating cost maintains around $28.50/MW while selling intelligently, and congestion pricing is then incorporated, a positive revenue should be produced. This is assuming that positive congestion pricing plays a strong role in the node being assessed. This concept is evaluated further in Step 3.

Step 3, now incorporating the congestion pricing, allows for Nodes A, B and C to have varying breakeven values. For Case 1 the following values were determined for each node:

- Node A Generating Cost – $33.52/MW
- Node B Generating Cost – $26.44/MW
- Node C Generating Cost – $28.72/MW

These values tell us that for Case 1, as long as the generating cost remains below the designated price at each node a profit can be made there with the addition of congestion pricing.

A unique feature notable for Node B is the fact that once the congestion pricing is incorporated into the model, the breakeven price for profit shrinks from that which only included the system price. When the system price was used for intelligent selling, a price $28.47/MW was determined, once the LMP was used in its place, the price for netting $0 revenue dropped by roughly $2/MW to only $26.44/MW. This signifies that there is a large amount of negative congestion pricing that forces the generating cost to lower accordingly to match a decreased electricity cost with the LMP. Nodes A and C do not encounter the same issue due to their often-positive congestion pricing.

5.2.2 Step 4 – The effects on congestion pricing

Using the breakeven price from Step 2 – selling efficiently against the system price – a curve can be determined to model the Net Revenue from congestion pricing per megawatt of generation. However, as more generation is input into the system, the positive congestion charges will diminish until there is

$0 in congestion pricing left in the system. As mentioned previously, this is calculated through the use of Lagrange Multipliers. It was found that, on average, each megawatt would alter the congestion pricing by about $1.15/MW starting after the first megawatt input.

It was also calculated that, on average, positive congestion pricing makes up about 2.3% of Node A's LMP while only about 1.3% of Node B's LMP and 1.8% of Node C's LMP. Figure 21 shows the breakdown of percent of congestion for each node throughout the year. Figure 22 shows the breakdown of hours by positive or negative congestion values for each node. Node A had the most hours with a positive congestion pricing and the least with a negative congestion pricing while Node B had the exact opposite. It had the fewest number of positive congestion hours and the most hours with negative congestion.

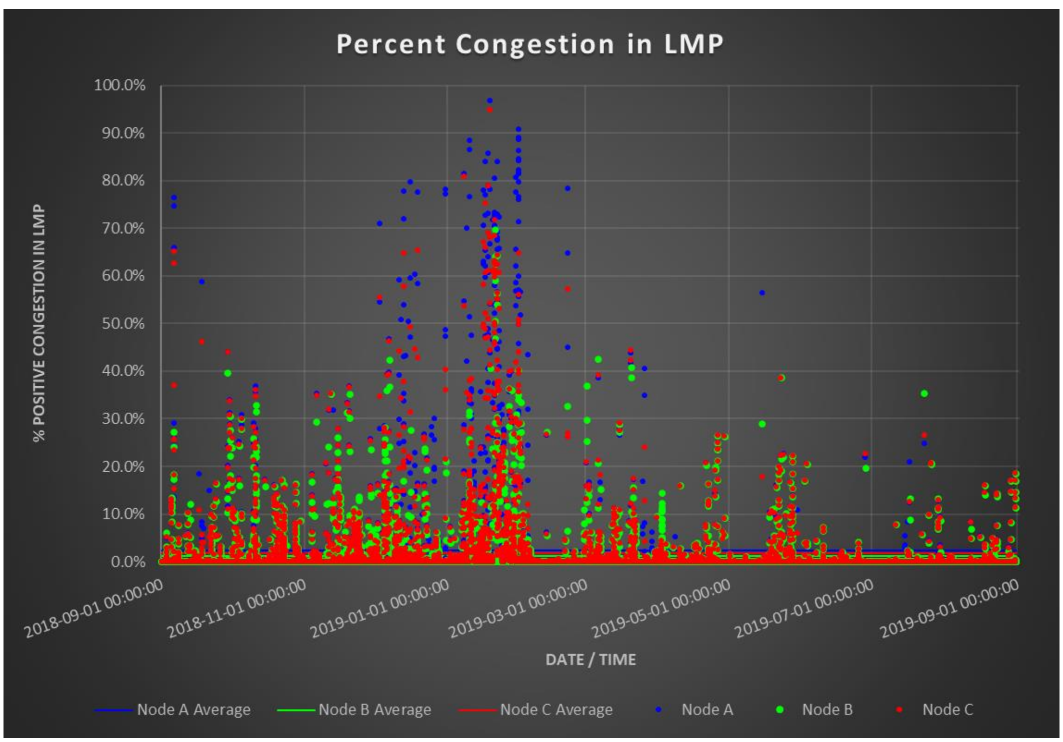


Figure 21: Percent Congestion in Locational Marginal Pricing

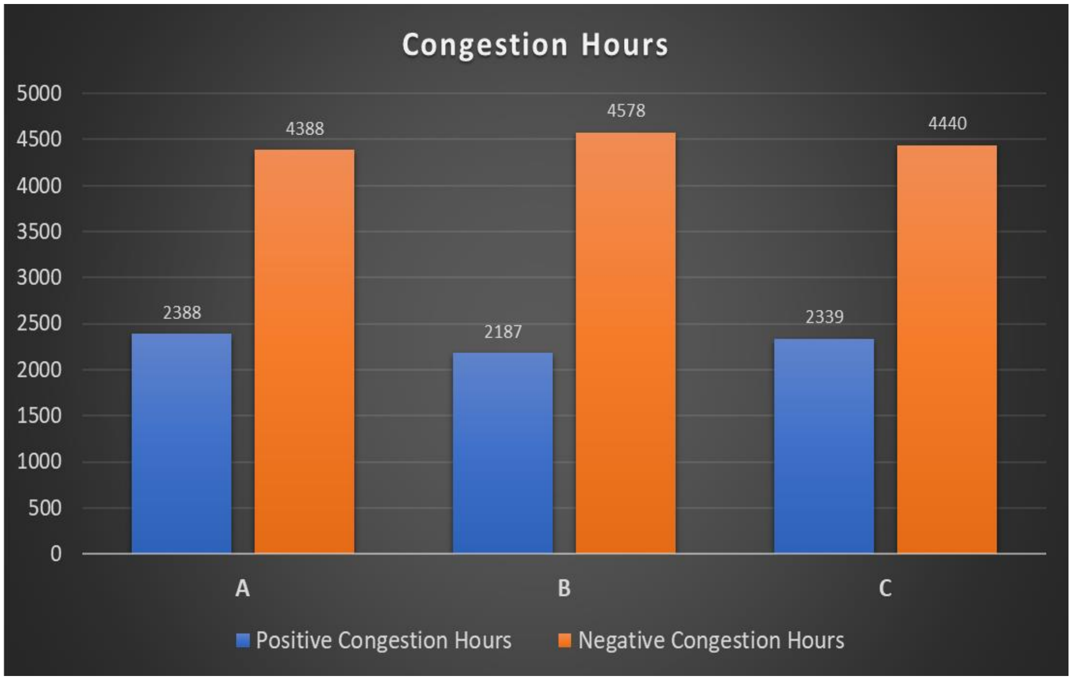


Figure 22: Congestion Hour Count by Node

Acknowledging the fact that Node A had the highest average percentage of positive congestion pricing while Node B had the lowest, it was consistently found that Node B would never produce a positive Net Revenue with the altering of congestion pricing. Node C would only provide about $730 for the first megawatt but lose money after that point. Node A, with the largest percentage of congestion pricing, provided the best result showing that the revenues would increase until 25MW with a revenue around $86,500 and would decrease after that point due to the effects on congestion pricing. This is displayed visually in the Figure 23. The ideal number of megawatts to install at Node A would be 25MW while it would not be fiscally responsible to build a power plant at Nodes B or C.

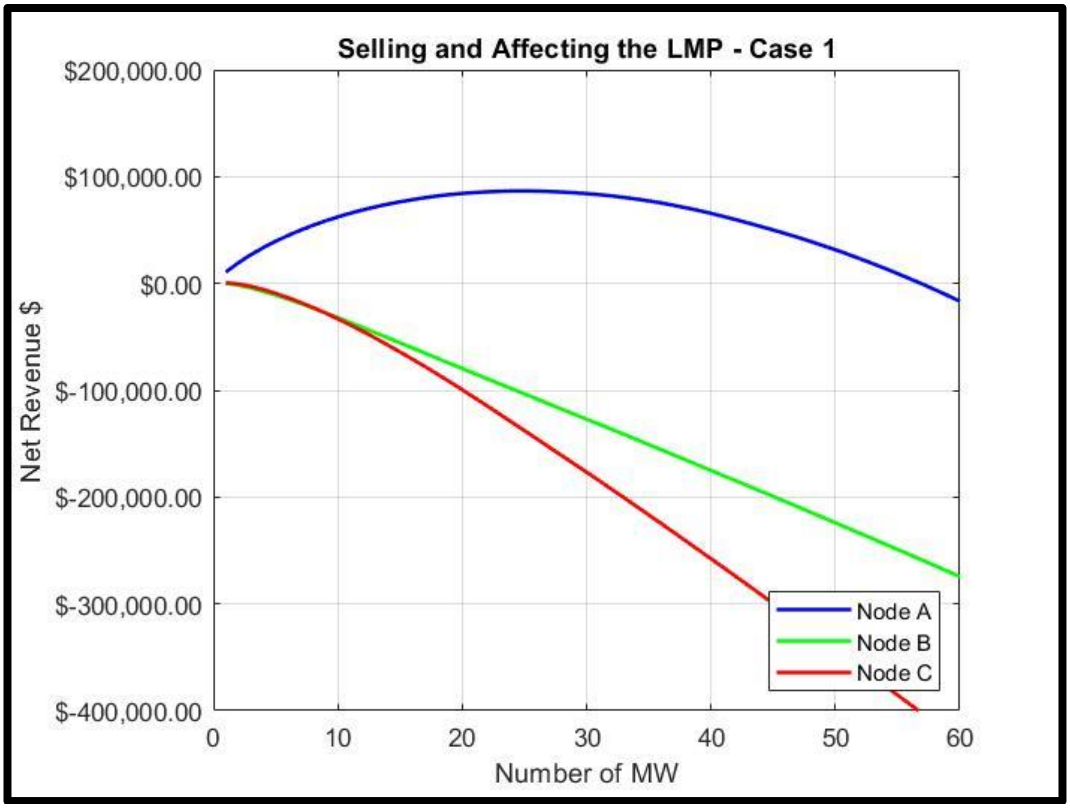


Figure 23: Selling Smart and Affecting the LMP in Case 1

5.3 Case 2 – Expanding a Sample Microgrid

The focus of the second case is on a primarily sustainability angle allows it to stand apart from Case 1 distinctly. Some losses are encountered because, in order to fulfill the Rutgers Microgrid load, the new generation is run despite the possibly negative financial impacts. In simpler words, the microgrid load is always satisfied despite the negative effects it may have. The savings – or losses – of this decision are accounted for in each step.

5.3.1 Steps 1, 2 and 3

It is important to keep in mind that the net revenue for Case 2 includes the savings and losses associated with the constant in-house generation as well as the savings from intelligent selling. However, incorporating the microgrid's load into

Case 2 does not alter the results from Case 1, Step 1. Because the selling – and usage for Case 2 – are both being performed 24/7, Case 1 and Case 2 both require a generating cost of $24.20/MW to have a zeroed net revenue. Step 2 strongly differs in Case 2 because smart generating techniques are implemented, however only for the excess production. For Case 2 to produce $0 of revenue while satisfying the microgrid load and intelligently selling any excess generation, a generating price of $25.34/MW must be achieved. As mentioned for Case 1 as well, varying the nodes between Nodes A, B and C will produce the same outcome for both steps because only the system price is reviewed. At this price, if congestion pricing is now incorporated, a profit can be made, which is evaluated in Step 4.

For the third stage of analysis Nodes A, B and C each have their own price for determining revenue based on their individual congestions. As long as the microgrid can produce for a price less than the breakeven price at each node below, the generator will not lose money.

- Node A Generating Cost – $25.30/MW
- Node B Generating Cost – $23.90/MW
- Node C Generating Cost – $24.02/MW

Matching the nodal pattern seen in Case 1, Node A, which had the largest percent congestion, produces the best opportunity for selling electricity. Nodes B and C are not in congested enough areas to benefit as successfully from new generation through a microgrid application.

5.3.2 Step 4 – The effects on congestion pricing

Due to constant internal generation to satisfy the load, there is a loss in revenue for the first 8-10MW of generation. Once the smart excess generation profit is added into the revenue, the curves begin to increase as show in Figure 24.

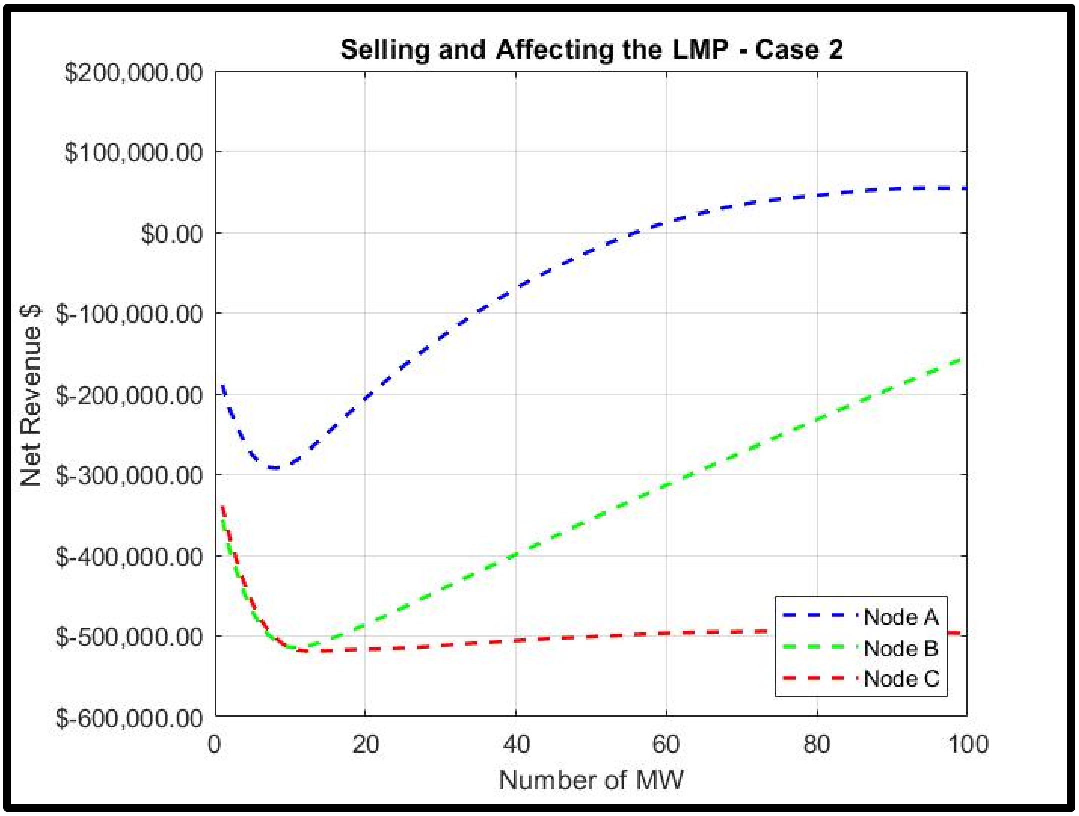


Figure 24: Selling and Affecting the LMP – Case 2

This demonstrates that for Rutgers, if the goal is to create a sustainable campus and make a small profit, it would be most ideal to install 97MW of new generation which would provide a revenue of just under $54,500 if it were located at a node similar to Node A. If Rutgers is located at a node similar to nodes B or C, incorporating this technique as in Case 2 would not provide a favorable outcome.

Chapter 6

Conclusion

6.1 Collection of Results

Case 1 and Case 2 presented two unique views for the incorporation of new high-efficiency turbine generation in response to electrical grid congestion. The former is solely economical while the latter focuses on a primarily more socially influenced viewpoint.

Case 1 presented itself as a more independent methodology by incorporating new power plant generation into pre-existing points in the grid. The sole purpose of Case 1 was to determine if congested points on the grid could benefit from new generation and become a profitable revenue source. Node A, which was determined to be the most congested Node reviewed, with an average congestion percentage of 2.3%, provided the best case. Nodes B and C did not contain enough congestion pricing and thus produced little to zero net revenue. Node A on the other hand could benefit from a small 25MW power plant installation and would net a revenue of about $86.500 while also lowering the congestion in that area.

Case 2 pulled in the concept of microgrid incorporation with economic benefits. Using the Rutgers Busch and Livingston microgrid and corresponding cogeneration plant as a sample case, new generation incorporation was modeled. Node A, again due to its more congested area, provided the best case. However, because the new generation was used to fulfill the microgrids load first, a larger megawatt input was required to produce a satisfiable net revenue. Ideally, for Case 2, Node A, 97MW of new generation would be required to produce a net revenue of about $54,500. Although the capital commitment for Case 2 is much larger than that for Case 1 and the revenue is smaller, the social implications of being a self-sustaining microgrids could outweigh the cost depending the view of the entities involved.

6.2 Summary

In conclusion, a thorough analysis was performed comparing opportunities of installing new turbine generation into the grid under different circumstances. What was found was a strongly situational result. The location of the new generation – or rather the electricity pricing and congestion influence at that point – is the key factor which influences the profitability and success of a new generating system. Whether new generation was installed independently or a preexisting microgrid was used, the Node still was the deciding factor. For Case 2, the existing microgrid infrastructure and associated load strongly manipulated the overall profitability of the new generation. However, a Node with a large congestion impact and percentage still is the main requirement for success.

6.3 Future Work

Further research should look into more nodes spread throughout the grid. Our thesis showed the strong influence of congestion on outcome; however, a larger nodal analysis could provide further insight. More specifically, it could determine how strong the congestion must be at a node for it to be an advantageous point. A larger sample size may provide a more generalizable and universally applicable result. Alongside that, more microgrid samples should be reviewed with different current generating system setups. Lastly, the incorporation of new turbine generation was evaluated, however, other methods of generation should be reviewed for different perspectives. Renewable generation – such as wind or solar – as well as different styles of turbine generation – such as cogeneration – should be analyzed due to their individual economic factors. Different generating mechanisms may prove more economically advantageous at different locations; further analysis could be determinate.

Chapter 7

Appendix

7.1 A Bit on Blockchain

7.1.1 What is Blockchain?

Blockchain is one of many distributed ledger technologies currently in use – a digital platform enabled by the computing, and internet technology infrastructure that is used to create a virtual marketplace in which transactions can occur. It operates with no central administrator or clearing house of records and transactions, but instead allows participants in the virtual marketplace to provide decentralized, peer-to-peer validation of the transactions. The benefit of using blockchain technology is that the transactions are immutable and digitally synchronized into a database built on defined consensus protocols (Pasi et al., 2019).

Cryptography, or a method of secure communication, is used to log, protect and communicate transactions so that they are validated by peers in the network and only allowed to be appended upon further transaction. The nature of transaction defined using blockchain technology is presented in the figure below

7.1.2 Blockchain in SMART systems

Blockchain technology has become widely view in terms of its expanding usages across multiple platforms. The energy sector is no different. The role of blockchain technology in the electrical grid is being explored to confront the many obstacles facing an aging grid and a growing market. With a growing market comes an increase in demand, however the "…existing transmission and distribution infrastructure is not designed to accommodate such new generation sources brought online, whether renewable or not" (Shah, 2017).

Blockchain has the inimitable opportunity to revolutionize the electrical grid through its integration into SMART-microgrid grid design as well as upgrading the existing electricity market towards a pro-renewable structure.

7.1.3 Peer-to-Peer trading

As mentioned in the previous section, one of the key features in a SMART microgrid – with the addition of a blockchain interface – is the incorporation of an advanced peer to peer trading system. There are many advantages to a peer to peer system. They promote local renewable generation which helps circulate the money internally, supporting the community as a whole. Also, when implemented within an islanded microgrid, they have the unique ability to continue trade during blackout periods thus meeting the demand of the community (Abdella & Shuaib, 2018).

The backbone of the blockchain interface is the predefine system of smart contracts on which the blockchain operates. These "smart contracts may be a potential solution to facilitate auditable multiparty transactions based on prespecified rules between market agents and, thus, increase the trustworthiness, integrity, and resilience of energy transactions" (Do Prado et al., 2019). These smart contracts allow users – whether it be for a smaller scale individual resident or larger scale commercial or industrial entity – to predetermine constraints for which they would like their personal system to operate. For example, generators can set limits for the smallest amount they will sell their energy for while consumers can set limits for the maximum amount they will pay. There even is the potential to mobilize this software through apps and thus allow real time controls such as those used by the Brooklyn Microgrid.

7.1.4 Benefits

Incorporated into microgrids and at key points in the macrogrid, blockchain has the potential to relieve congestion, revolutionize energy efficiency, increase data security, and optimize the use and encourage the incorporation of new technologies into the power grid. The IEA has stated that "The overall savings from these digitally enabled measures could be in the order of USD 80 billion per year over 2016-40, or about 5% of total annual power generation costs based on the enhanced global deployment of available digital technologies to all power plants and network infrastructure" (IEA 2017).

The movement towards smart grids and digitalization of the energy system means the grid is starting to function in three layers. The primary layer is the physical layer of electrical flow through the network. The second is the digital or communication layer consisting of collected data from meters and other sensors. Finally, there is the virtual layer, or the data stream. Smart meters are an example of a point of connection between the digital and the virtual layer.

With smart devices at every node in a grid, blockchain could be used within the virtual layer to verify and use the digital layer data points to map the physical layer's flow through the grid. Essentially, blockchain could collect accurate, secure data on real time grid congestion. Utilizing the three different types of blockchain – public, consortium, and private – the virtual layer could support a nest network of information providing data to different clients based on their stake in the information (Wu 2018). According the IEA, digital energy security requires the consideration of three concepts, resilience, cyber hygiene, and “security by design, i.e. the incorporation of security objectives and standards as a core part of the technology research and design process,” (IEA 2017). Therefore, as the digital and virtual layer to the power grid move past stages of infancy, there should be technology growing with the system to ensure its security rather than trying to incorporate it later. “The characteristics of blockchain decentralization, high-redundancy storage, high security, and privacy protection help solve some of the security problems faced by information and physical systems,” (Wu 2018). Blockchain is able to fulfill all three of the IEA digital security concepts and as well as preform other required tasks for the chosen technology, ensuring the survivability and future development of these new layers to the current grid infrastructure. It supports opportunities for smart contracts and intelligent controls to expand the current capabilities of SMART grids by embracing the cultivation of the aforementioned digital and virtual layers.

Chapter 8

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