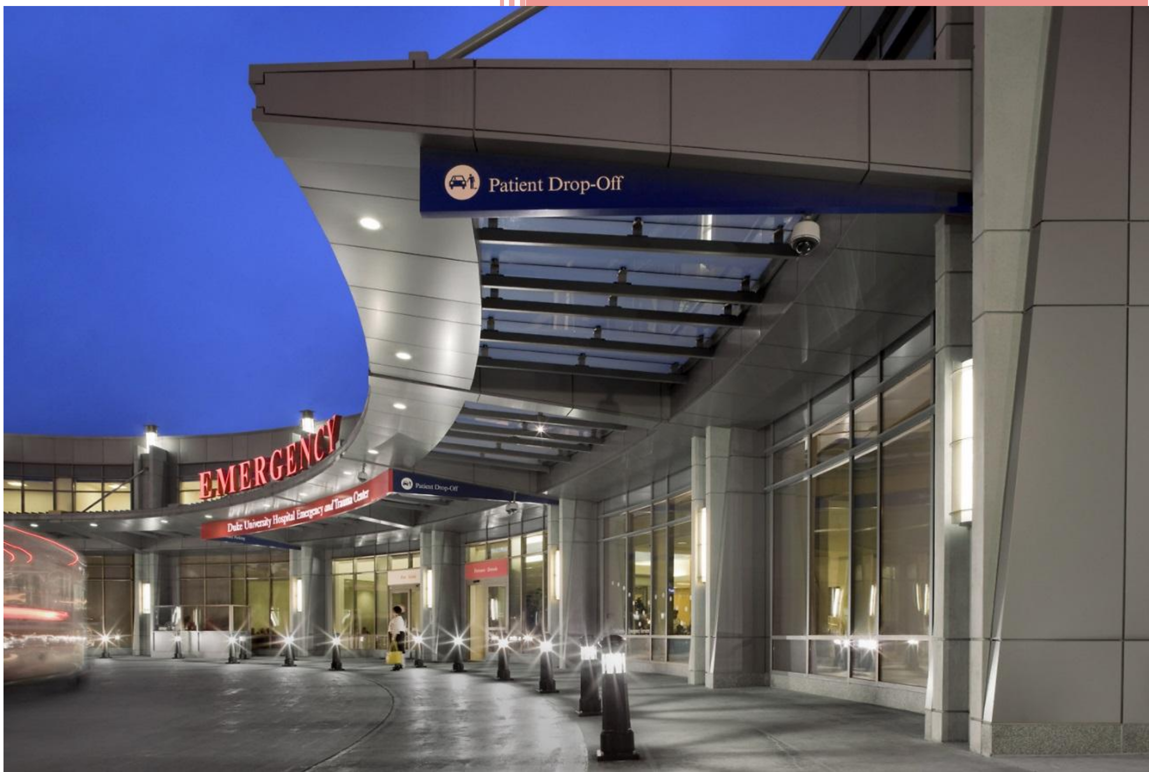
Duke University Health System Demand Response Prospectus



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Masters Project Submitted in Partial Fulfillment of the Requirements for Duke University's Nicholas School of the Environment's Master of Environmental Management Degree

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Executive Summary

The *Duke University Health System Demand Response Prospectus* is a client-based Master's Project that explores the financial and environmental impacts of enrolling Duke University Health System and Duke University in Duke Energy's PowerShare demand response program.

Demand response programs are mechanisms used by utilities to decrease energy demand during high-usage periods (e.g. hot days when air conditioning use is highest) by incentivizing their customers to reduce grid consumption for a limited time. This temporary demand reduction results in cost savings to utilities because it allows them to avoid using their most inefficient and expensive power plants.

In this study, we analyze the economic, environmental, and regulatory feasibility of using Duke University and Duke Medicine emergency generators in a Duke Energy demand response program (PowerShare Generator Curtailment Option). Duke Carbon Offset Initiative credits, a Duke University funding mechanism to reduce carbon dioxide emissions, were also considered as a potential revenue source. In order to calculate the impacts of enrollment, a Microsoft Excel model was created. The model allows the client to quickly conduct our analysis in response to future conditions, such as changes to the university generator fleet, fuel prices, or PowerShare program changes.

Major Findings:

- Enrollment in the current PowerShare program is not economical for two main reasons:
    1. DUHS and Duke University would lose their exemption from Duke Energy's demand side management (DSM) rider. Since the DSM rider is a per kWh fee assessed to total annual energy consumption, and the university is a large energy consumer, the costs outweigh the credits of participation.
    2. PowerShare fuel compensation is lower than current cost of producing energy from diesel generators, the norm for standby generators and the university.
- Enrollment would increase global carbon dioxide emissions. PowerShare participation is expected to increase the carbon emissions due to the low emission rate of Duke Energy's natural gas peaking plants. Assuming a peaking plant, with an emissions rate similar to a coal plant, the Duke Carbon Offset Initiative would have to offer $3,197 to $23,440 per ton in carbon offset credits. The average range paid for carbon offsets is currently $5-10 per ton.
- Individual conditions for PowerShare enrollment to be revenue neutral:
    1. Curtailment credits would need to increase from $.10 to $.26 per kWh for demand response events to be revenue neutral.
    2. The current DSM rider must decrease from $.000724 per kWh to a range of $0 to $.0005 per kWh. At PowerShare's low fuel compensation rates, even negating the DSM rider would result in losses beyond 20 annual hours of curtailment.
- Model results have been recently validated when the only Duke University PowerShare generator pulled out of the current program after experiencing losses.
- We recommend negotiations with Duke Energy to waive or decrease the demand side management rider, increase current PowerShare curtailment credits, or allow the most efficient generators to be enrolled into the program under a consolidated account.

Introduction

Duke University Health System (DUHS), “the health care delivery arm” of Duke Medicine, was founded in 1998 to strengthen its clinical service capabilities on the university campus and expand its healthcare network[1]. It provides training sites, research opportunities, and a network of reliable healthcare providers including Duke Clinic, Duke Raleigh Hospital, Duke Regional Hospital, and Duke University Hospital. Although it is separately managed, it is closely linked to Duke University, the School of Medicine, and the School of Nursing. It also has an extensive area of jurisdiction, called the Duke Medicine, which forms much of Duke’s West Campus. Due to a common history and close proximity, DUHS has frequently collaborated with Duke University and adopted similar views on a variety of issues including sustainability.

Duke University Carbon Neutrality

In 2007, President Richard Brodhead committed Duke University to an ambitious 2024 carbon neutrality goal by signing the American College and University President’s Climate Commitment. Although Duke University’s initial steps toward this goal have been incredibly successful, the largest carbon reduction opportunities, such as replacing coal with natural gas on campus, have already been implemented. Moving forward, Duke recognizes the need to use carbon offset credits to achieve its carbon neutrality goal. Duke University’s goal for carbon neutrality currently excludes DUHS. Therefore, projects funded by Duke University which reduce DUHS emissions can be directly attributed to university reductions. Enrollment in a Duke Energy demand response program may be one such project opportunity to generate carbon offsets. Demand response programs are incentive plans created to reduce end-use energy consumption. They are utilized by utilities to minimize the use of economically (and often environmentally) inefficient plants when the grid is near capacity. The desire of DUHS and Duke University to institutionalize sustainability and improve its environmental performance has led to this Masters Project between Duke University Health System and the Nicholas School of the Environment to evaluate the feasibility of increased demand response enrollment for backup electricity generators on campus.

[1] Duke University Health System. *DUHS Strategic Plan Summary*. Retrieved from http://www.dukemedicine.org/repository/dukemedicine/2007/03/05/16/32/53/4178/DUHS_strategic_plan_sum.pdf

Background on Demand Side Management and Demand Response

Energy use has predictable trends of high and low demands. Power plants can be generally categorized into those that are regularly called upon to satisfy normal energy demands and the ”peaking” plants which only run on occasions when demand is exceptionally high (e.g. very hot days when everyone turns on their air conditioning units). Although these high-demand times are infrequent and last for short periods of time, these peaking plants dramatically increase the required capacity of the electrical grid due to the need for reliability. The larger the difference between peak and normal demand, the more expensive it is for electricity providers. Building additional electrical generation plants in order to satisfy the high demand periods, such as extreme hot or cold days, is both capital and resource intensive. An emerging alternative to these costly infrastructure investments is demand response.

Demand response is a type of demand side management (DSM) program used by utilities such as Duke Energy, the utility which serves Duke University. Utilities have traditionally addressed growing demand by adding more power plants. Rather than adding more supply, demand side management looks to decrease consumer demand-- thus mitigating the need to build more power plants. In order to fund its DSM programs, such as energy efficiency projects and demand response, Duke Energy charges its customers a DSM rider. The DSM rider is a small fee assessed to each kWh sold and is applicable to all electricity provided by Duke Energy. However, Duke Energy currently allows its large consumers, such as Duke University, to opt-out of the DSM rider if they independently implement energy efficiency programs.

Demand response is defined by the Department of Energy as programs that cause “changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[2]” These programs reduce demand at peak periods by asking consumers to decrease their energy consumption or to generate on-site power for a limited time. Demand response has become an

[2] Environmental Protection Agency. *Motivating Energy Efficiency with Metering Technologies*. Retrieved from http://www.epa.gov/statelocalclimate/documents/pdf/background012208.pdf

important component in maintaining balance in the supply and demand for electricity. In fact, its use is expected to nearly triple by 2020[3].

DUHS and Duke University, similar to other traditional electricity consumers, rely on Duke Energy for its electricity needs. As a large commercial user, it is also eligible for Duke Energy's commercial and industrial demand response program called PowerShare. This program offers four different options each with its own set of requirements as described below: PowerShare Mandatory, Voluntary, Generator Curtailment, and Call Option[4,5,6]. The program has a minimum three year requirement and requires the participant to opt-in to the DSM rider. The descriptions of the four current Duke Energy PowerShare options are listed below:

Mandatory Curtailment: This is a contract that requires businesses enrolled in the program to decrease or maintain electricity usage at an agreed upon level during Duke Energy initiated curtailment periods. In exchange for participation businesses will receive monthly capacity credits based on the load they agree to curtail and energy credits for the amount of energy actually curtailed. There is a 200kW minimum load and a maximum of 100 hours of curtailment per year. There is a cap of 10 hours per day and a minimum advanced notice of 30 minutes.

Capacity payment: $3.50/kW-month
Energy credit: $.10/kWh with a $2/kWh non-compliance penalty
Facility Fee: $40/month

Voluntary Curtailment: This option allows businesses to opt into curtailment on an event to event basis. Businesses will be able to view the energy price offered for the event before choosing whether or not they want to participate. This is only available at Duke Energy's discretion and provides the businesses curtailed energy credits for the

[3] Martin, Richard. *Load Curtailment from Demand Response Will Nearly Triple by 2020*. Navigant Consulting. Retrieved from http://www.navigantresearch.com/newsroom/load-curtailment-from-demand-response-programs-will-nearly-triple-by-2020
[4] Duke Energy. *Demand Response Overview*. Provided by J. Koone.
[5] Duke Energy Carolinas. *PowerShare: Profit from curtailing your energy use*. Retrieved from http://www.duke-energy.com/pdfs/110539-PowerShare-Bro-Carolinas-WEB.pdf
[6] Duke Energy. *Duke Energy Carolinas Integrated Resource Plan 2011*. Retrieved from http://www.energy.sc.gov/files/view/2011DukeEnergyCarolinasIRP_Public.pdf

equivalent load for each event. This is not available with PowerShare Generator, although possible with PowerShare Mandatory. Participants must provide at least %50 of what they agree to in order to receive payment but will not be penalized for nonperformance.

Generator Curtailment: This is also an emergency option that requires businesses to curtail use during utility initiated events but unlike the Mandatory PowerShare program, participation in this program also enables Duke Energy to transfer load to the private generator. Businesses will receive capacity payments and energy credits for the load curtailed. The minimum load is 200kW and has a maximum of 100 hours of curtailment per year, 10 hours per day, and 15 minutes advance notice.

Energy Credit: $.10/kWh with $2/kWh non-compliance penalty
Capacity Payment: $3.50/kW-month
Facility Fee: $155

Call Option: This program requires businesses to reduce and maintain their load to a predetermined level during curtailment periods in order to receive a monthly credit based on the load curtailed during events. This has a minimum requirement of 100kW and a maximum of 5 emergency events per year. Participants are informed at least 6 hours prior to the emergency event, which should not exceed 8 hours, and the day before an economic event.

Energy credit: $.045/kWh
Capacity Payment: $.83-$2.50/kW depending on economics events

Due to the research intensive nature of many of the buildings on West Campus and the stringent reliability requirements for medical facilities, service disruption is often not optional and rules out several of these curtailment programs. This study will instead explore the standby generators on Duke University's campus for enrollment into Duke Energy's Power Share Generator program which would allow DUHS and Duke University to offset demand on the Duke Energy grid. By request of the client, the scope of the project will be limited to generators on campus.

During curtailment periods, enrolled generators will be obligated to produce a contracted amount of power. In this way, the buildings they serve will demand less power from the Duke Energy grid. For example, at current PowerShare Generator rates, a 1000 kW generator that curtailed its full capacity for a one-hour emergency event would earn $3500 in capacity payments and $100 in curtailment energy credits for that month. The costs for enrollment include a $155 monthly facility fee, the DSM rider payments, and any fuel used by generators to fulfill PowerShare requirements.

The Duke University Health System's large collection of standby generators is a good opportunity to explore demand response enrollment, reaffirm its commitment to sustainability, and help Duke University reach its carbon neutrality goal. It is also an opportunity for the hospital to decrease its operating costs, providing much needed savings as medical personnel shortages and other financial concerns puts pressure on decreasing margins[7]. Additionally, the reliable and large DUHS generator fleet is seldom used and could be readily enrolled in PowerShare without significant changes to their maintenance or operational regimes.

Currently, four medical center generators are enrolled in a legacy Duke Energy demand response program, the Standby Generator Control Program (SG). Although SG has historically proven profitable, it will be phased out by 2015[8].

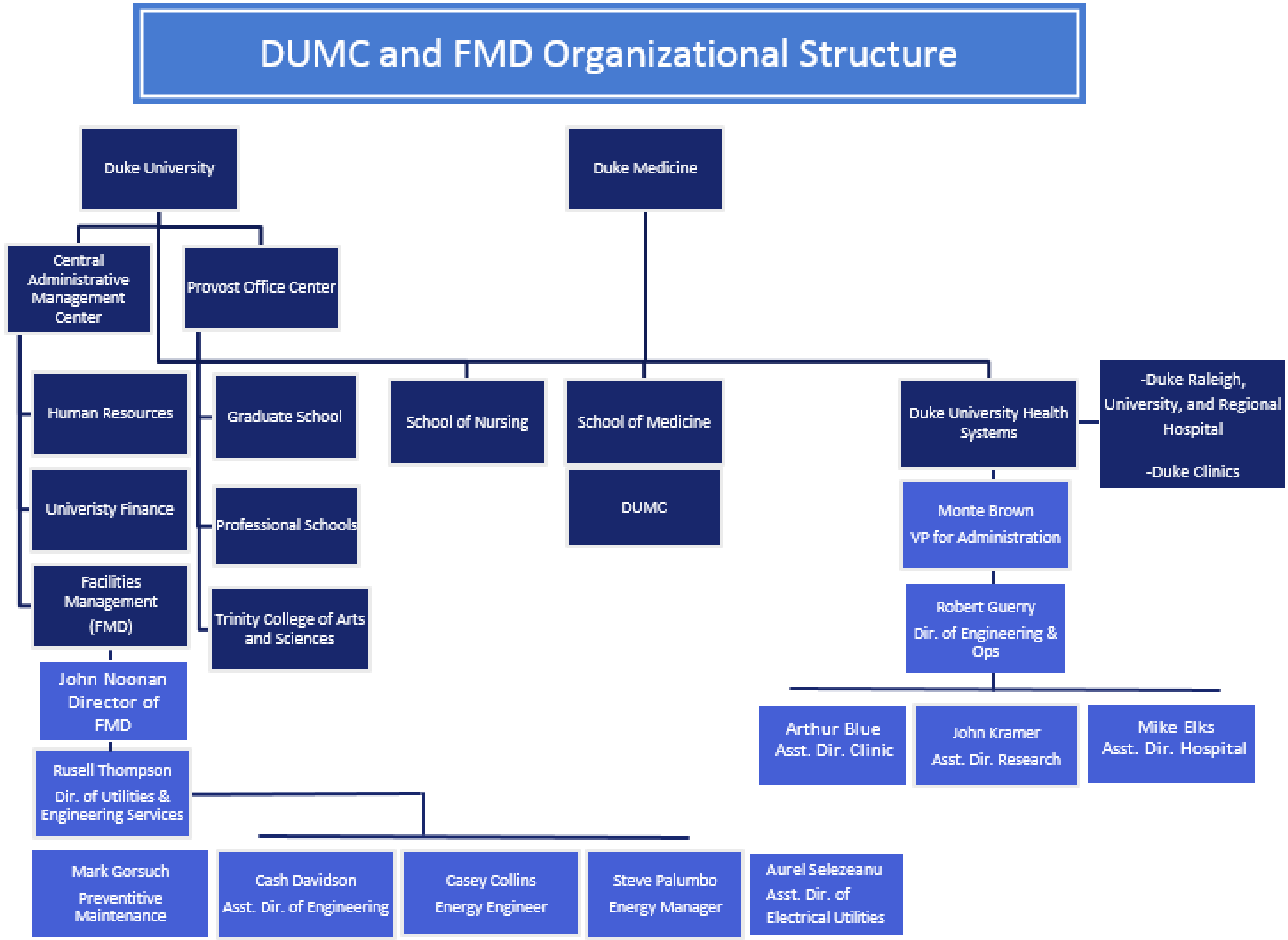
Organizational Structure

The buildings, which the generators of interest serve, comprise the majority of Duke's West Campus and belong to both Duke University and DUHS. Despite the close proximity of these generators, they fall under different administrative units. Buildings belonging to Duke University are maintained by Duke University Facilities Management Department and buildings on the medical side are maintained by the Medical Center Engineering and Operations group. It was very

[7] Schneider Electric. *Energy Efficiency for Hospitals*. Retrieved from http://www.schneider-electric.com/sites/corporate/en/support/white-papers/energy-efficiency-for-hospitals.page
[8] J. Koone (personal communication, November 1, 2013).

important to understand the complex organizational structure of Duke University and DUHS for practical reasons such as data collection and obtaining the right permission for generator enrollment. Additionally, it is important in identifying relevant stakeholders and understanding the interactions between these various groups (Figure 1).

Figure 1. This figure shows the organizational structure of DUMC and FMD.



Organizational Strucuture created based on information obtained through expert consultations and from presentation given by Billy Newton, Vice Dean for Fiance and Resource Planning for Duke School of Medicine http://medschool.duke.edu/files/documents/Faculty_presentation_FinalWebsite.pdf

Data Collection Methodology

In this analysis, we identify the optimal combination of generators for enrollment in Duke Energy’s PowerShare Generator program. Data was collected and analyzed to determine if optimal generator enrollment could provide environmental and economic benefits.

Expert consultations were determined as the best way for project scoping and data collection. Although energy management is an analytics-driven field, much of this information is kept as proprietary. Therefore, instead of solely relying on a traditional literature review of scholarly articles and books, we decided to also utilize our information networks.

Chart 1. Lists the informational interviews and expert consultations used in this study.

Organization	Name	Position
Duke Energy - PowerShare Program	Jeff Koone	Senior Account Executive for Large Businesses
Duke Energy	Michael W. Stroben	Director of Environmental Policy Analysis & Strategy
Duke University Medical Center – Engineering and Ops	John M. Kramer	Assistant Director of Engineering, Medical Research Campus
Duke University – Facilities Management	Steve Palumbo	Energy Manager
Duke University – Facilities Management	Aurel Selezeanu	Assistant Director of Electrical Utilities
Duke University – Facilities Management	Mark Gorsuch	Preventative Maintenance
Duke University – Facilities Management	Cash Davidson	Assistant Director of Engineering
Duke University – Facilities Management	Casey Collins	Energy Engineer
Duke University Medical Center – Occupational and Environment Safety Office	Karen Trimberger	Manager of Environmental Programs
Duke University Medical Center– Occupational and Environment Safety Office	William Brewer	Director Environmental Programs
Duke University Medical Center– Occupational and Environment Safety Office	Wayne Thomann	Director Occupational and Environmental Safety
Bensinger and Garrison Environmental Inc	Doug Bensinger	President

Duke University Office of Project Management	Floyd Williams	Project Manager
Gregory Poole Power Systems	Joe Tripp	Senior Account Manager

Based on our expert consultations we were able to gain a better understanding of the energy infrastructure on the Duke Campus. Duke University and DUHS are large sized commercial clients to Duke Energy and lack options for continuous, on-site electricity generation. Similar to households, Duke University and DUHS are connected to the Duke Energy power grid, but unlike other smaller customers, Duke University and DUHS both have internal divisions that function as a utilities system operator. Once the energy is transmitted from Duke Energy and enters the campus boundaries through five jointly owned substations, it is distributed by Facilities Management and Engineering and Operations. Although all substations are dedicated to serving the Duke University, each substation is billed separately. Therefore, the five substations result in five individual accounts. This is significant in our study because Duke Energy requires PowerShare participants to opt-in to the DSM rider, an account-level fee, as a requisite to enrollment. Consequently, our analysis examines the profitability of PowerShare relative to each of the five accounts on campus.

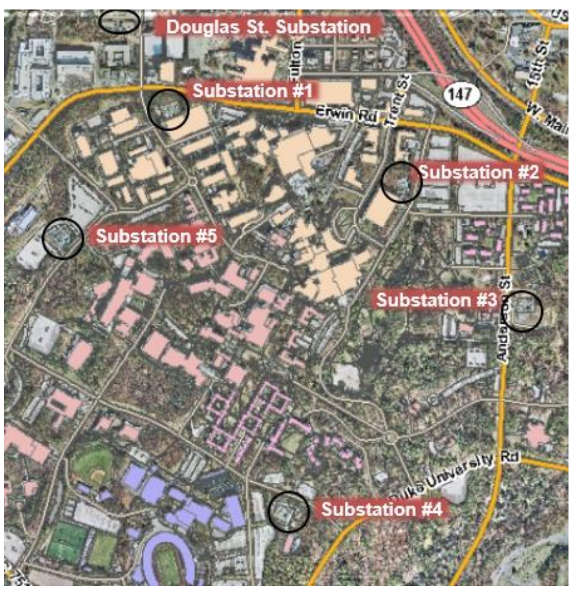
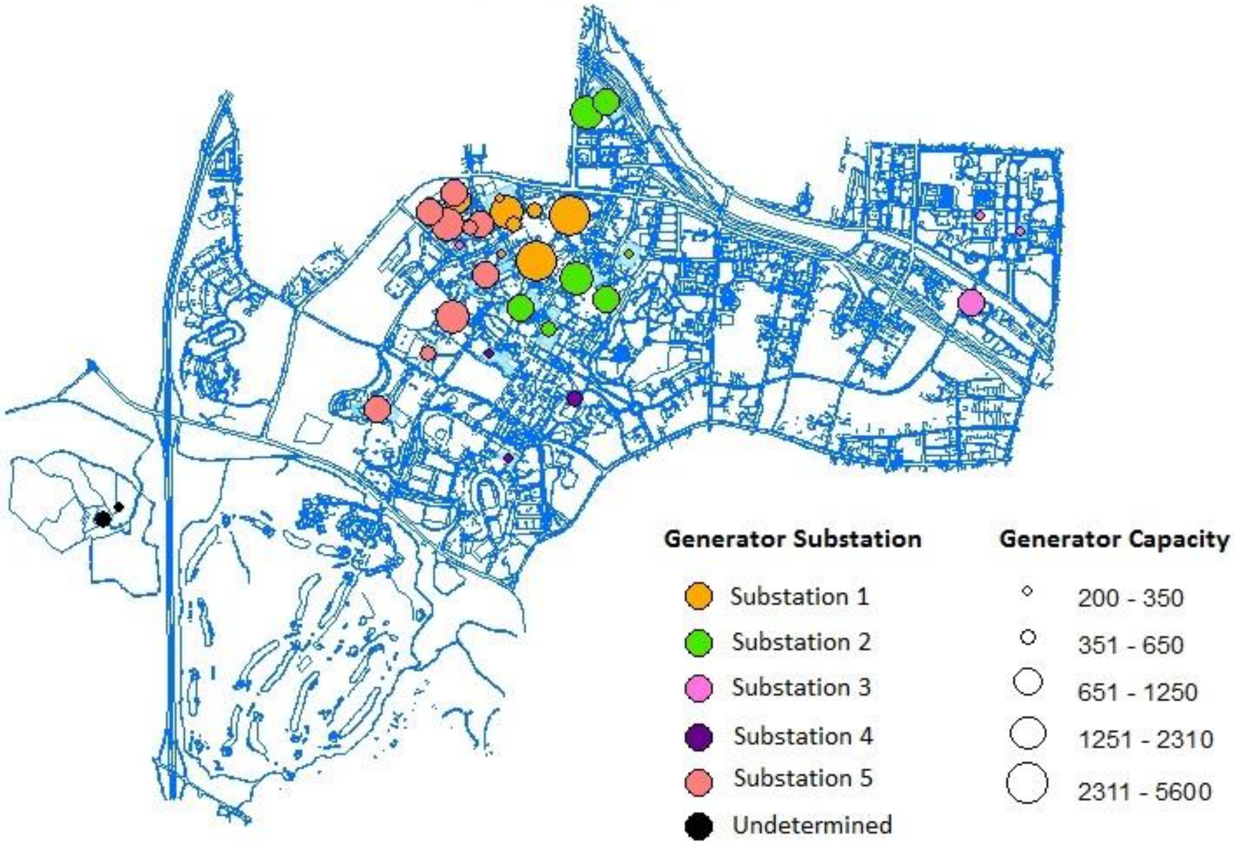


Figure 2. Shows the location for each of 5 substation on campus. Obtained from Casey Collins.

Duke University Campus - Generators by Capacity and Substation



Model

Generator selection for the PowerShare program is largely driven by economics: DSM rider fees, fuel costs, carbon offset opportunities, and the potential for financial gains through capacity and energy curtailment credits. Environmentally, we also analyze the ability of Duke's standby generators to provide carbon dioxide reductions relative to Duke Energy's peaking plants. In order to best evaluate the cost-benefits and risk-benefits for individual generators and the full network, an Excel model was created. The Excel model references user-defined factors (e.g. fuel rates, generator specifications, PowerShare requirements) to evaluate the candidacy, profitability, and net grid emissions of individual generator enrollment in the PowerShare Program.

The client requested the creation of a user-friendly model so future analyses could be easily and quickly conducted. It was very important to provide a streamlined, yet flexible tool for the university's energy managers to quickly conduct analyses on the demand response feasibility due to fluctuating energy prices, evolving regulatory testing requirements, and other variables. For example, diesel fuel (the predominant source of emergency generator fuel) prices can fluctuate significantly over the course of a year, generators can also be added or retired, or the requirements of the demand response program itself are subject to change. Therefore, a model was requested to understand the impacts of these changes, making it a timeless tool to analyze PowerShare profitability and to identify prime generators for enrollment in demand response. An Excel-based model, with user-friendly macros, was created to satisfy the client's needs. The following section describes the methodology of the data collection process, assumptions, main variables, and default values incorporated in the model.

Model Data Collection Methodology

Chart 2. Describes sources of all datasets used in study.

Data Set	Source / Organization
Generator List DUMC	Mark Gorsuch (Duke DUMC)
Generator List FMD	Cash Davidson (Duke FMD)
Generator Air Permitting and Compliance	Karen Trimberger (Duke EHS)
Substation Connections	Aurel Selezeanu (Duke FMD)
Fuel Consumption Data 13 DUMC Generators	Randy Teasley (Duke DUMC)
Demand Response Duke Energy Specifics	Jeff Koone (Duke-Energy)
"Master Generator List"	Shuai Zhang ('13 Nicholas Alumni) and Karen Trimberger (Duke EHS)
Campus GIS Data	Karen Trimberger (Duke EHS)
Generator Spec Sheets	Manufacture and Distributor Websites (See Spreadsheet)
Duke Carbon Offset Information	Charles Adair (Duke DCOI)
Diesel and Gas Fuel Rates	Energy Information Administration

Our expert consultations helped us obtain several important data sets (Chart 2) for our study including a list of all generators within DUMC and FMD. These data sets had limited emissions information, fuel consumption information, geographic location, installation date, and generator details. Due to the incomplete data, another section specifically gathering data from generator manufacturers was added on to our study. The main objective was to complete the existing data set with fuel consumptions rates and emission data. This was essential to producing accurate characterizations of the generators in our model due to the large variation in generator efficiency and performance.

One of the major challenges in this process was the lack of comparable manufacturer specification sheet and the lack of information on many of the less popular generators. The fuel consumption and emissions rates for older installations were especially hard to locate. Manufacturers like Caterpillar, Kohler, and Cummins, only provide newer product sheets. In order to obtain specification sheets beyond their current product offerings, diesel generator archives from used generator distributors were also utilized.

Another complication in obtaining fuel consumption rates is the interchangeable use of generator model and engine model numbers in the original data sets from DUMC and FMD. Generator sets are assembled by various manufacturers using different engine models. For example an SR-4 engine can be used in a Caterpillar 3412 Generator, D343 Generator, or in a generator bearing the engine name. This makes identifying generator models difficult when given only the engine model.

In order to identify the generator models, several data sets obtained from Duke University administration, were crossed referenced. This strategy was used to identify the majority of generator model numbers. Then using the compiled generator data, generator models were extrapolated based on generator characteristics such as kW capacity, voltage, amps, date of installation, and pattern structure of the serial number. These methods identified another large section of generator models which was then used to obtain system performance specifications and fuel consumption rates. Using cross referencing and extrapolation based on generator characteristics, all but 15 generator models were identified and matched with fuel consumption rates.

The remaining generator specifications were filled out using a widely utilized average diesel generator fuel consumption chart from a generator supplier[9]. This course of action was appropriate because the fuel consumption chart from Diesel Service and Supply is referenced to by several diesel generator supplier sites and matches the widely accepted industry "rule of thumb", which approximates that fuel consumption rates are roughly 7% of total generator capacity[10],[11]. This "7% rule of thumb" is mentioned in literature from Critical Fuel Systems (BSF

[9] Diesel Service and Supply, Inc. *Approximate Fuel Consumption Chart*. Retrieved from http://www.dieselserviceandsupply.com/temp/Fuel_Consumption_Chart.pdf
[10] Worldwide Power Products. *Diesel Fuel Consumption Chart*. Retrieved from http://www.wpowerproducts.com/resources/diesel-fuel-consumption
[11] Green Mountain Generators. *Fuel Consumption For Diesel Generators*. Retrieved from http://greenmountaingenerators.com/fuel-consumption-for-diesel-generators/

Industries)[12], All World Diesel[13], and Excel Power[14]. One exception to this 7% assumption is a document by Engineers without Boarders which uses a 10% fuel consumption rate, but the organization's work is in developing nations which may also impact the efficiency of generators[15]. The alternative to using the average diesel generator fuel consumption chart would have been to create an average based on a sample of diesel generators. This alternative was explored but abandoned in favor of using the chart average due to the possibility for inaccuracy due to the limited size of the sample (six to seven generators per each of the four-size category and pre-2000 category). Additionally, the results of the process were comparable to the results of the fuel consumption chart.

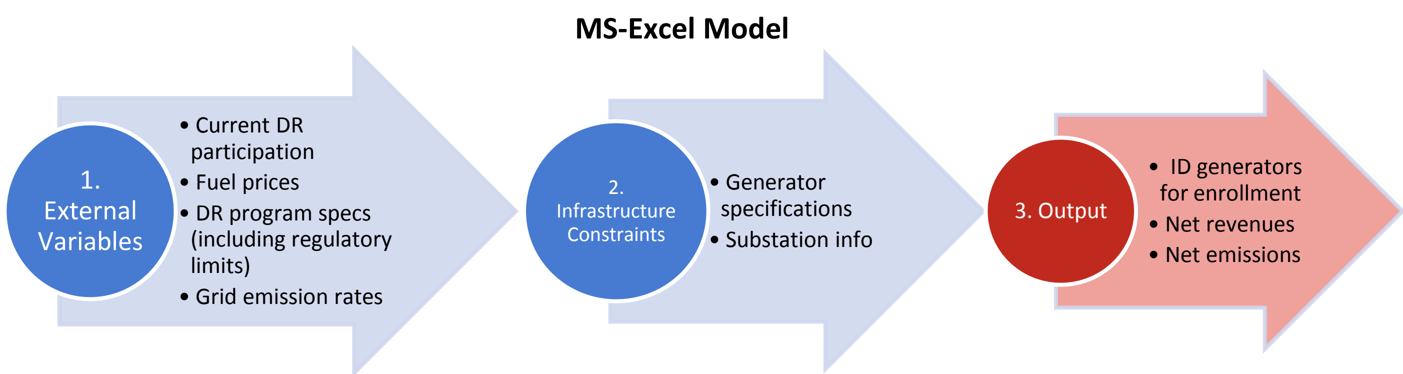


Figure 3. Overview of model considerations by inputs, base data, and output.

As depicted in Figure 3 (above), the model's output is contingent on two types of inputs: external variables and infrastructure constraints. External variables are time-varying factors outside the university's control such as fuel prices and grid emissions rates. The model allows the user to input these external variables into the model, allowing the model to be quickly adapted to reflect market changes. The model then uses these external variables to do financial and enrollment feasibility calculations to see which generators can be potentially used in demand response programs. Candidate generators are then examined and compared for their

[12] Critical Fuel Systems. *An Engineering Guide to Modern Fuel Systems*. Retrieved from http://www.criticalfuelsystems.com/wp-content/uploads/2010/05/Design-Guide-print-22.pdf
[13] All World Design. *Advanced Power Systems*. Retrieved from http://www.allworlddieselgen.com/faq.htm
[14] Excel Power. *Diesel Generator Frequently Asked Questions*. Retrieved from http://www.excelpowerltd.co.uk/sitedata/files/Excel_Generators.pdf
[15] Engineers Without Borders. *Diesel Generators.* Retrieved from http://www.ewb-usa.org/theme/library/myewb-usa/project-resources/technical/DieselGenerators.rtf

infrastructure constraints, which describe physical conditions such as the specifications of individual generators including emissions, fuel consumption rates, and their respective substations. The model then produces the final output, a list of generators and substations which yield positive revenues and environmental benefits when enrolled in the PowerShare program.

Model Sheet: "Parameters"

The "Parameters" tab contains the user-defined inputs such as pricing and the demand response program details. Of these, the most important cost factor is the demand side management rider (DSM rider). The DSM rider is a per-kWh, substation-level charge defined annually by Duke-Energy. Currently, the rider is set at $0.000736 per kWh. Although this charge seems small, it represents an approximate 1% cost premium because it applies to the total annual energy use at a given substation.

In order for an emergency generator to be eligible for PowerShare, the university must opt-in to paying the DSM rider fee and total energy consumption at the generator's corresponding substation over the last calendar year.

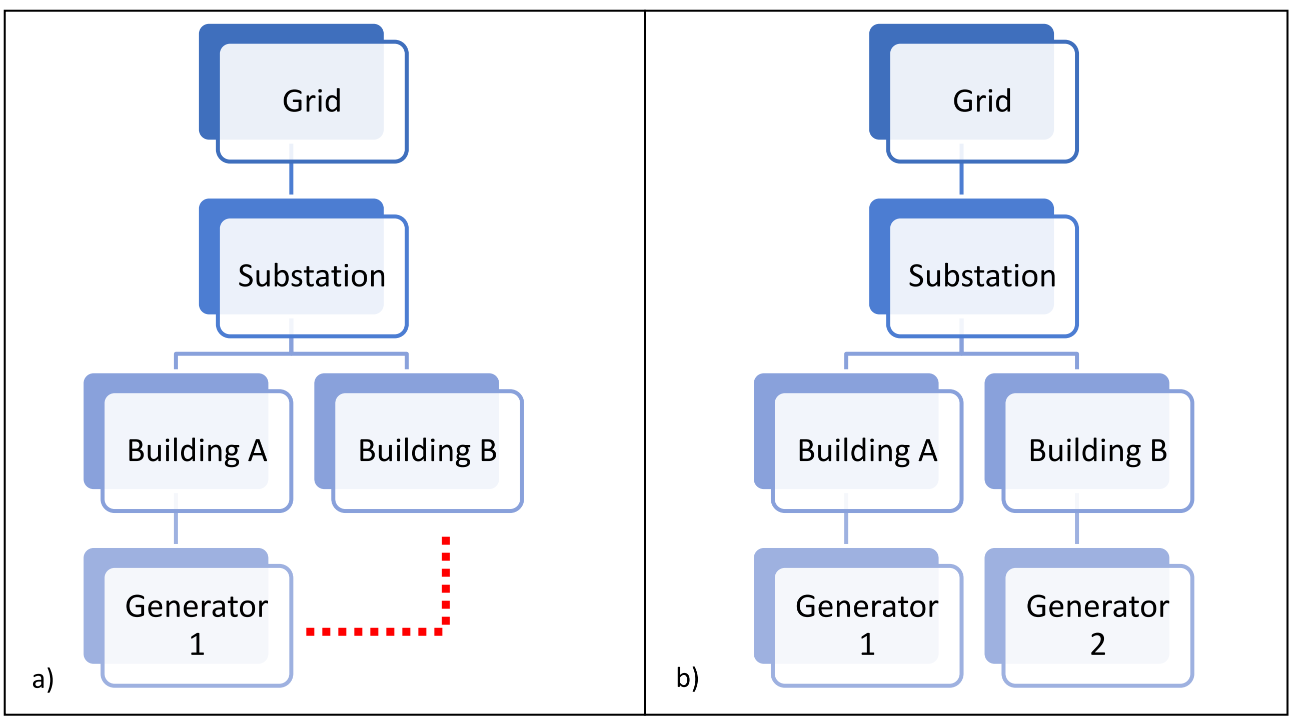


Figure 4a and Figure 4b. Generator-substation diagrams.

Figure 4a and 4b conceptually illustrate the energy delivery infrastructure of the university and medical center campus. The electricity from Duke Energy is first sent to one of five substations on campus before then being distributed to the end use building. Each substation is metered individually and serves a select group of buildings. In the event of a large grid failure, power is supplied to the buildings using energy backup generators. Figure 4a shows the situation when one generator has enough capacity to support multiple buildings while Figure 4b shows buildings with separate backup systems.

As previously mentioned, the university's campus and medical center campus is powered by Duke Energy through one of the five campus substations. As a large energy consumer, the university and medical center campus faces large potential DSM rider fees that would amount to tens to hundreds of thousands of dollars. Because the DSM rider payment is applied to the full energy usage of the substation regardless of the number of generators enrolled, it is unlikely that enrolling one generator in PowerShare will result in enough capacity payment revenues to offset the large DSM rider. However, enrolling multiple generators under one substation will generate more profits without increasing the fixed DSM cost. The model selects which substations (and generators within them) should participate because demand side management participation occurs on an opt-in basis.

The utility also requires the demand response participants to pay for a generator-level meter which measures demand response activities ($125 per month). Along with the direct utility payments, the university must also cover any fuel costs associated with generator runtime during mandatory testing and emergency events. Currently, the university has 64 diesel generators and 2 natural gas generators.

Demand response costs are offset by two types of utility payments: capacity payments and curtailment credits. Capacity payments are a per-kW payment based on the amount of generation capacity enrolled in PowerShare. In contrast, capacity payments are per-kWh credits that are given by the utility to the university for energy produced from its generators during emergency events.

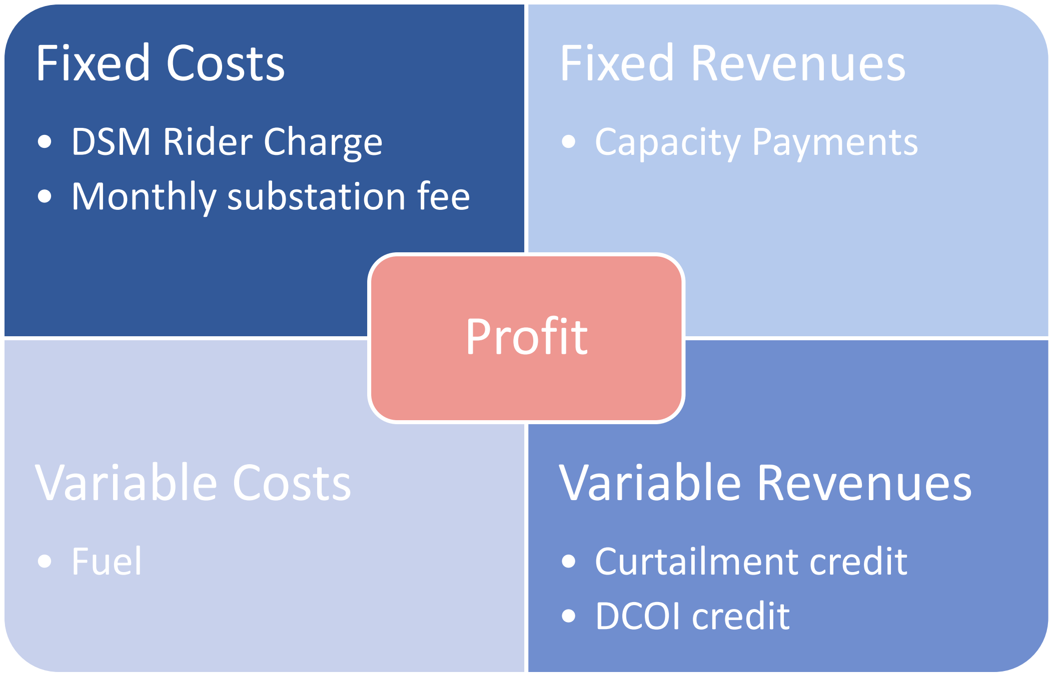


Figure 5. Modeled factors affecting PowerShare profits.

Figure 5 summarizes the cost and profit drivers considered by our model. Labor was not included in our analysis because the additional labor required for demand response participation would be marginal[16]. Part of the reason is that many of Duke's generators are controlled by an automated system with central controls. With these controls, turning generators on and off can be done remotely and quickly.

Operations and Maintenance (O&M) costs were also not considered because the additional runtime would have a negligible impact on generator performance and repairs. In fact, running the generators more frequently may have a positive impact on reliability. Because diesel generators are typically only used for testing purposes (~12 hours per year), a main reliability concern is that the diesel fuel will coagulate from sitting for long periods. Consequently, more frequent runtimes could help prevent coagulation.

[16] J. Kramer (personal communication, October 31, 2013).

Model Sheet: "Generators"

The "Generators" tab is where the infrastructure variables are defined. Columns A-H are strictly identifiers (e.g. location, building name, asset number, etc.) and are not used in the model calculations.

"Generators" Sheet Features: "Testing Requirements"

The accreditation agency is used by the model to determine the business-as-usual testing requirements. The model calculates the differential in annual fuel consumption between testing required by PowerShare and each accreditation agency.

Duke University's medical facilities abide by testing standards developed by the Joint Commission (JC). Under these standards, hospitals are required to test an average of 7.33 hours per year—half an hour per month with a four-hour test every three years. Facilities with research activities are governed by Duke University standards, set at a cumulative 6 hours per year—30 minutes per month. Lastly, academic buildings with no research or life support systems are governed by National Fire Protection Association (NFPA) standards, also set at 6 hours per year.

Consequently, PowerShare will result in increased testing (and thus fuel consumption) for generators abiding under JC, NFPA, or Duke University standards. If the standards change, users can adjust the testing hours in the "Parameters" sheet.

"Generators" Sheet Features: "Substation"

As previously discussed in the "Parameters" section, a generator's substation connection has a significant impact on its economic feasbility to enroll in the PowerShare program. The model was built to automatically calculate the total DSM fee for each substation and the potential capacity payments for each generator if enrolled. The model in its initial step compares the cost of the DSM fee with the capacity payments to see if the enrollment of that particular generator will yield a profit or a loss. If the enrollment of the generator will produce a net profit, then the model will continue to the process and calculate the expected profits for the maximum number of hours that Duke Energy may call upon. If the generator is found to be profitable in both evaluations of the DSM fee and with the maximum curtailment hours Duke Energy can request, then a substation and its eligible generators are recommended by the model for enrollment in the PowerShare program.

"Generators" Sheet Features: "Capacity and Reserve Ratio"

Duke Energy's PowerShare Program requires all participating generators to be able to meet its minimum curtailment capacity of 200kW. The model reviews the generator specifications, and more specifically the capacity figures in column K, to eliminate the generators that are unable to meet this minimum curtailment capacity. While the capacity figures in column K gives the rated capacity of a generator, it does not provide the actual building-level energy consumption. Since it is common for building designers to oversize their generator recommendations, an analysis based solely on rated capacity is unreliable. Therefore, the model was designed to take a conservative approach and accounts for this uncertainty using the user-defined "reserve ratio" in column M. Most building managers or facilities personal will have a more accurate understanding of the actual building energy usage and whether or not the generator was oversized. This knowledge is incorporated into the model by having a user defined reserve ratio that reflects the estimated oversizing of the generator. The reserve ratio is then multiplied by the rated capacity in order to approximate the amount of curtailable load which is reported by the model as "constrained capacity'. A reserve ratio of 25% on a 1000kW generator, for example, would only allow 750kW to be enrolled in PowerShare.

Model Sheet: "Consumption"

The "Consumption" sheet provides fields for annual substation-level energy consumption. The default values used in our model are the actual 2012 figures. The model uses the values from this sheet to calculate the potential DSM fees for each substation. Although these figures do not reflect the most recent calendar year, the results are still valid because substation level consumption varies little from year to year[17].

Model Testing

While the model has a core set of built-in assumptions, the model also offers a wide range of utility due to the flexibility of user defined features. The model can be a useful analytical tool to address many different questions depending on the scenario it is supposed to replicate. The final model results will also vary depending on the scenario assumptions. Several of these scenarios, which are explored in the following sections, were created to apply the model in different environments.

Status Quo Scenario: Model Sheet "Scenario 1"

"Scenario 1" is the first analysis run by our model which analyzes PowerShare relative to the status quo, such as the program's current framework, and the university's generator infrastructure. It assumes a modest price in Duke Carbon Offset credits at $10 per ton and off-road diesel costs at $3.56[18]. This scenario also uses two different emissions rates, one for peak hours during which curtailment events would occur and one during off-peak hours for the generator testing hours. The average peak emission of 1538.14 pounds of carbon dioxide per MWh was based on eGrid data for natural gas plants that will likely be used in quick ramp up periods[19]. The off-peak hour was based on the average grid emission from the Environmental Protection Agency (EPA) at 1130 pounds of carbon dioxide per MWh[20]. While the historic rate is around 4 hours of curtailment per year, the full spectrum of curtailment hours from 0-88 were modeled in order to better understand the potential impact of curtailment hours on financial feasibility of the program with changing demand. The ceiling for the range is set at 88 hours because standby generators are only allowed to run a maximum of 100 hours before being

[17] S. Palumbo (personal communication, November 4, 2013).
[18] Energy Information Agency. *Does EIA publish off-road diesel fuel prices?* Retrieved from http://www.eia.gov/tools/faqs/faq.cfm?id=14&t=5
[19] J. Koone (personal communication, November 1, 2013).
[20] Environmental Protection Agency. *Power Profiler*. Retrieved from http://www.epa.gov/cleanenergy/energy-and-you/how-clean.html

subjected to more stringent air quality rules and are required to do 12 hours of mandatory testing per month. The 4 hours of curtailment scenario can be treated as the baseline scenario.

CO2 Intensive Scenario: Model Sheet "Scenario 2"

"Scenario 2" is similar to "Scenario 1" in its attempt to model realistic market conditions, but assumes a peaker plant with a coal plant emissions rate. The parameters from Scenario 1 are held constant except the emissions rate for peaking plants is increased. The peaking rate assumes the use of a coal plant at 2440.45 pounds per MWh (the average emissions rate of a North Carolina coal plant) in order to create the most favorable conditions to the potential of using carbon offsets. Although a coal plant is unlikely to be used as a peaker in practice, due to coal's limited ramping ability, the analysis provides an upper bound on the carbon emissions reduction potential.

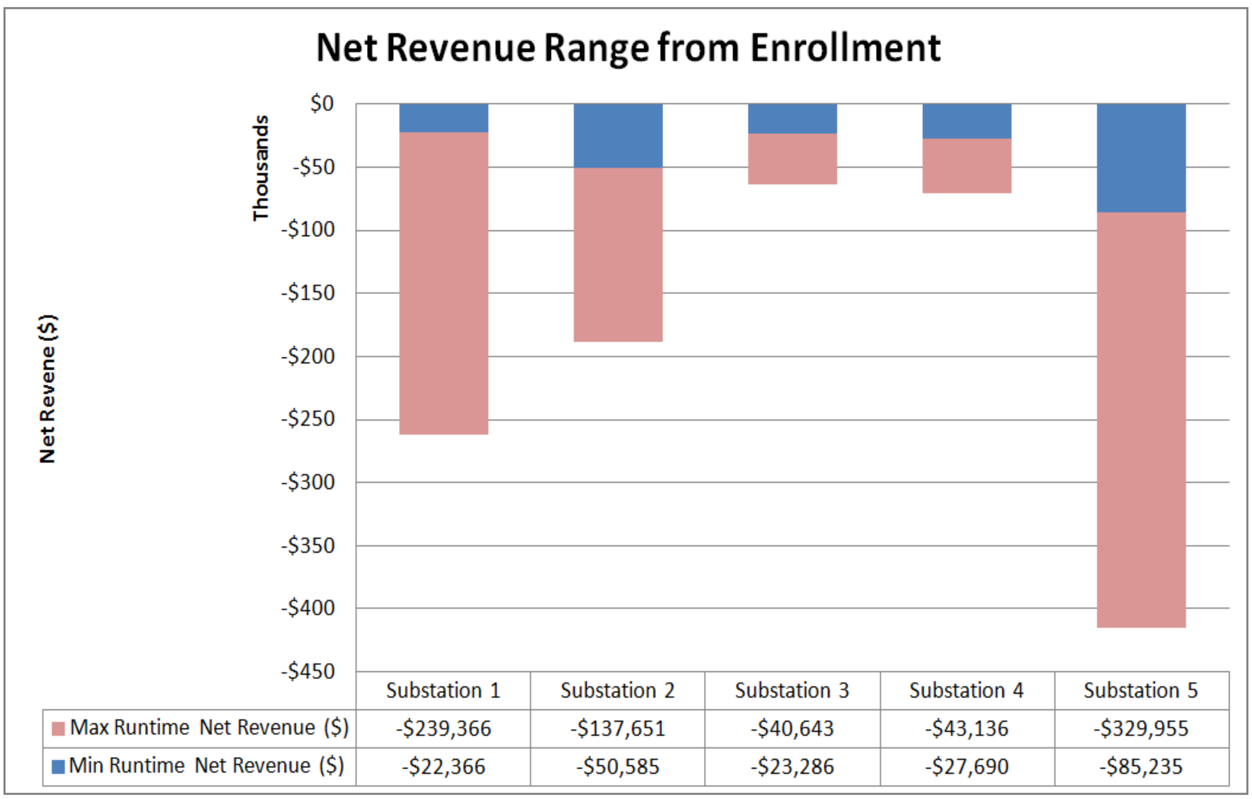
Duke Carbon Offset Evaluation

One of the original objectives of this project was to evaluate the possibility of using Duke Carbon Offset Initiative credits to help make demand response more attractive. This was evaluated in two different ways. Since credits are determined by the Duke Carbon Offset Initiative on a case to case basis, an adjustable function was created in the "Generator" sheet to allow the user to substitute in the final carbon offset price and evaluate the financial feasibility of the option. This feature in the model builds-in flexibility and allow the user to react to price changes. The expected carbon offset price ($10) was then used to evaluate the financial feasibility of demand response in "Scenario 1". Second, a break-even carbon offset price was also evaluated to identify the price point at which carbon offsets would make demand response revenue neutral under current conditions.

Results

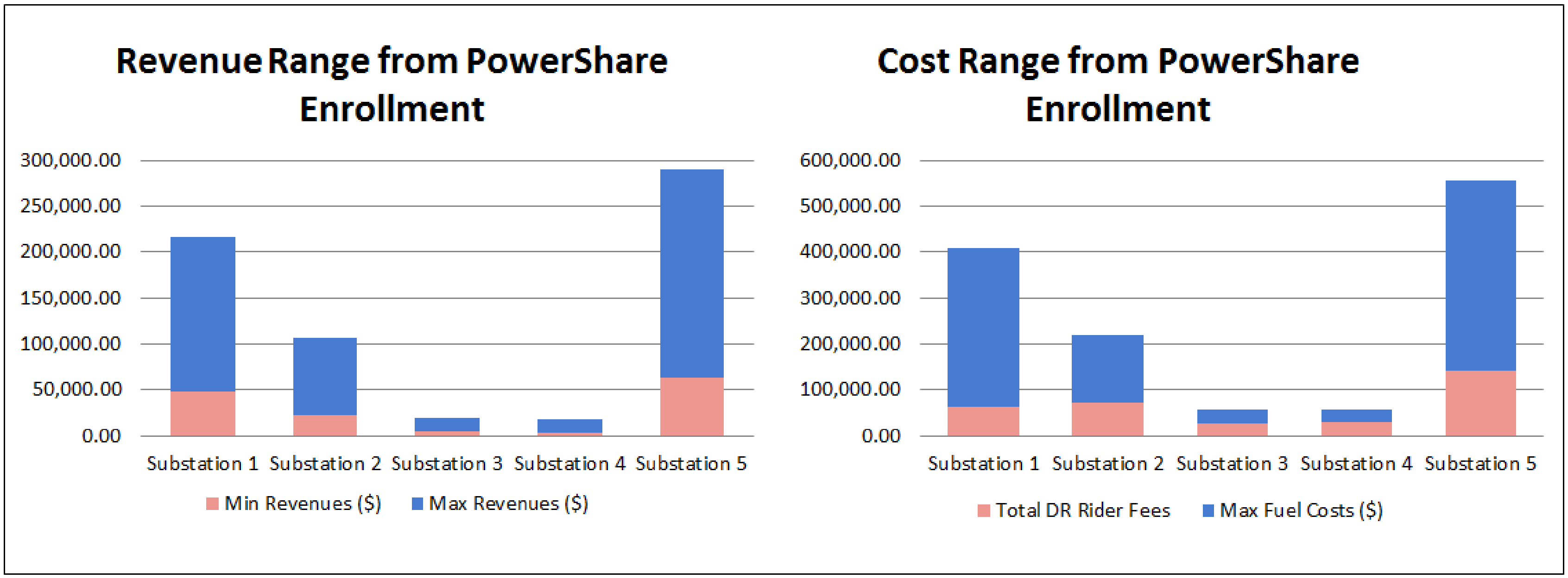
Based on our analysis, demand response enrollment is not currently a viable option from either an environmental or financial perspective. As seen in Figure 6, substation enrollment will yield losses ranging from tens of thousands to hundreds of thousands in net losses. The blue base depicts the net revenue of initial enrollment: the revenue (capacity credits and curtailment credits for generator testing) minus the cost (demand side management rider and fuel costs of testing). The pink portion of the graph depicts the net revenue of enrollment over a period of time in which there is the maximum 88 hours of curtailment Duke Energy can call for.

Figure 6. Net revenue range over 88 hours of demand response runtime.



Figures 7 and 8 break down our analysis into revenue and cost. Enrollment costs comprise of the demand side management rider fee and fuel costs of testing. The demand side management rider fee is the largest component of the cost because it is based on Duke University's (the enrolled substation's) energy consumption. Consequently, the demand side management rider charge is so high on all five substations that it outweighs the revenue generating opportunities in the PowerShare program. With the minimum of zero hours of demand response curtailment, Duke should expect to lose between $22,366 and $85,235 per substation.

Figure 7 and 8. Revenue and Cost Ranges from PowerShare Enrollment.



Compounding the problem is that the PowerShare's curtailment credit is lower than what diesel generators can currently produce-- the marginal costs of the program exceed the marginal revenues. As depicted in Figure 9, any curtailment hours will further reduce Duke University's profits from the program. The most efficient generators in Duke University's fleet can produce energy at approximately $.25 per kWh, however PowerShare only provides $.1 per kWh. As a result, each kWh produced in a demand response event will lose Duke-Energy $.15.

Factors Required for PowerShare Enrollment

While the results of this study clearly show that neither environmental or financial reasons currently justifies the enrollment in the PowerShare Program, this study goes on to further explore the ideal environment needed for program enrollment. In the sections below several factors and their impact on enrollment feasibility will be considered.

Decline in Diesel Fuel Price

By our analysis, diesel fuel prices need to fall to about $1.25 per gallon in order for curtailment events to be a revenue-neutral opportunity. In our analysis, we assumed that diesel prices were $3.56 (North Carolina highway prices less state and federal taxes).

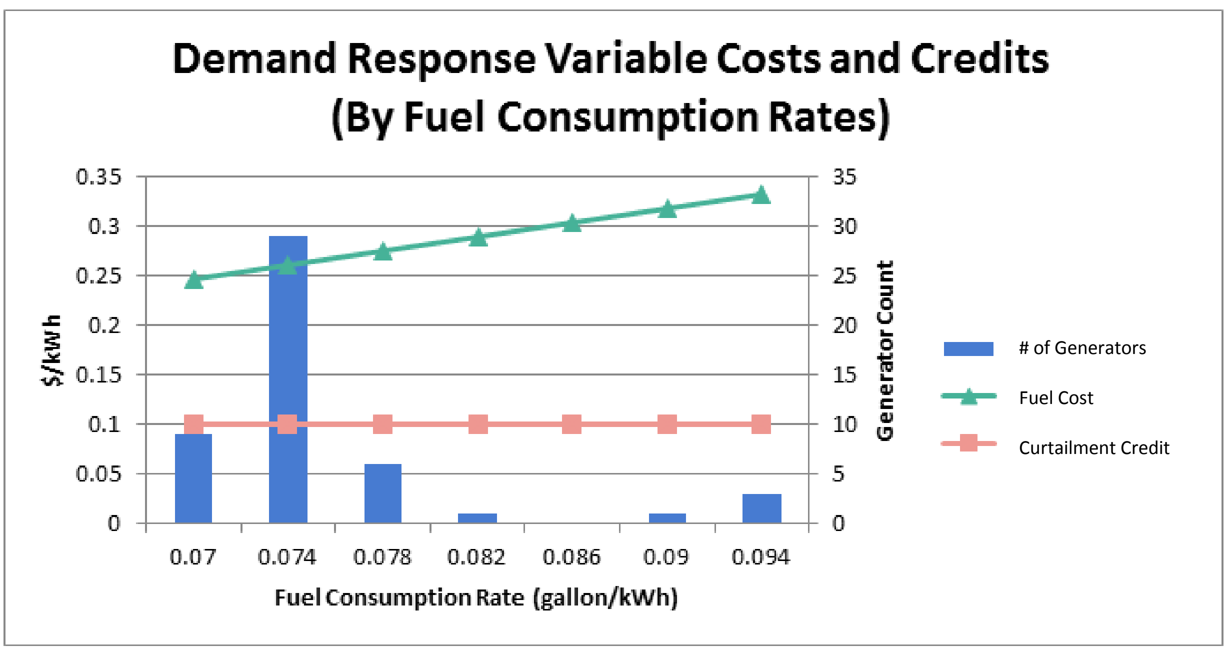


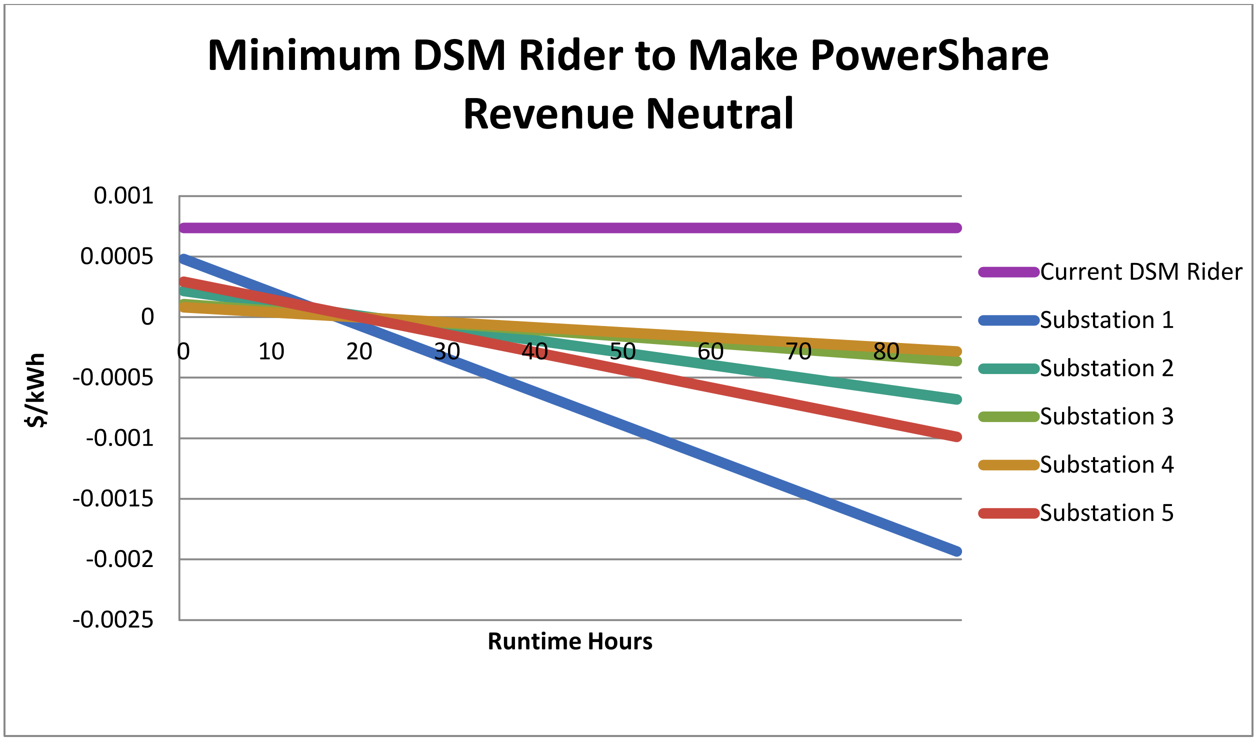
Figure 9. Demand Response Marginal Revenues and Costs

As illustrated in Figure 6, expected profits from PowerShare enrollment are strictly negative. PowerShare enrollment would be unprofitable to Duke University for two main reasons: the fixed DSM rider rate is too high and the variable curtailment credits are too low. As previously described, the DSM rider is a fee assessed to each kWh consumed. As a result, Duke University's DSM rider payments would be large because the university consumes significant amounts of energy. At the university's current consumption, even at zero curtailment hours, the fixed cost of enrollment (primarily the DSM rider) is greater than the fixed revenue (PowerShare capacity credits).

Therefore, we sought to provide a range of DSM rider rates which would make PowerShare a revenue neutral opportunity for Duke. The results of our analysis are shown in Figures 10 and 11. The graphs are broken down by substation because the DSM rider is charged at the substation level. Because energy consumption differs by substation, the DSM fees will differ as well. Runtime hours were used as the independent variable to account for the expected losses associated with every additional hour of curtailment.

As seen in Figures 10 and 11, the required DR rider fee varies significantly by substation with zero hours of curtailment, ranging from \$.0001 to \$.0005 per kWh. For reference, the current DR rider is \$.000724 per kWh. As the curtailment hours increase, the minimum DR rider rate decreases to account for the curtailment losses. Despite the variability in initial substation DR rider rates at zero hours of runtime, the lines all become negative around 20 hours of runtime. Where the lines are negative represent rates at which Duke-Energy would need to *pay* Duke University (beyond its curtailment credits) to ensure it does not lose money on PowerShare enrollment. An alternative way to interpret the lines crossing zero at approximately 20 hours of runtime is that Duke University would find PowerShare profitable (as long as it did not provide more than 20 curtailment hours) if it was not charged a DSM rider fee. Given that Duke University has only been called on once to exceed 20 curtailment hours (in 1998, Duke curtailed 29.2 hours), Duke should consider PowerShare enrollment if the DSM rider can be renegotiated or negated.

Figure 10 and 11. DSM Rider Rates to make PowerShare revenue neutral. Figure 11 depicts only the positive rates.



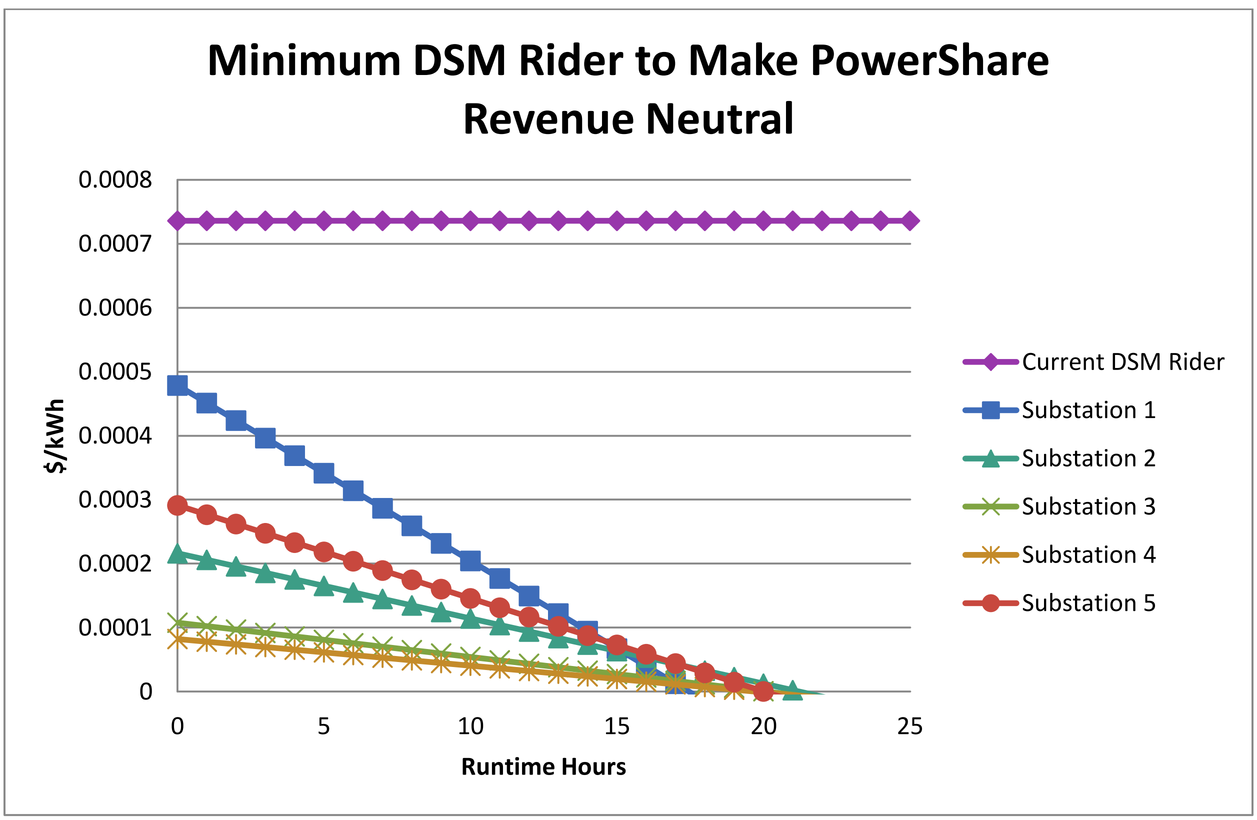
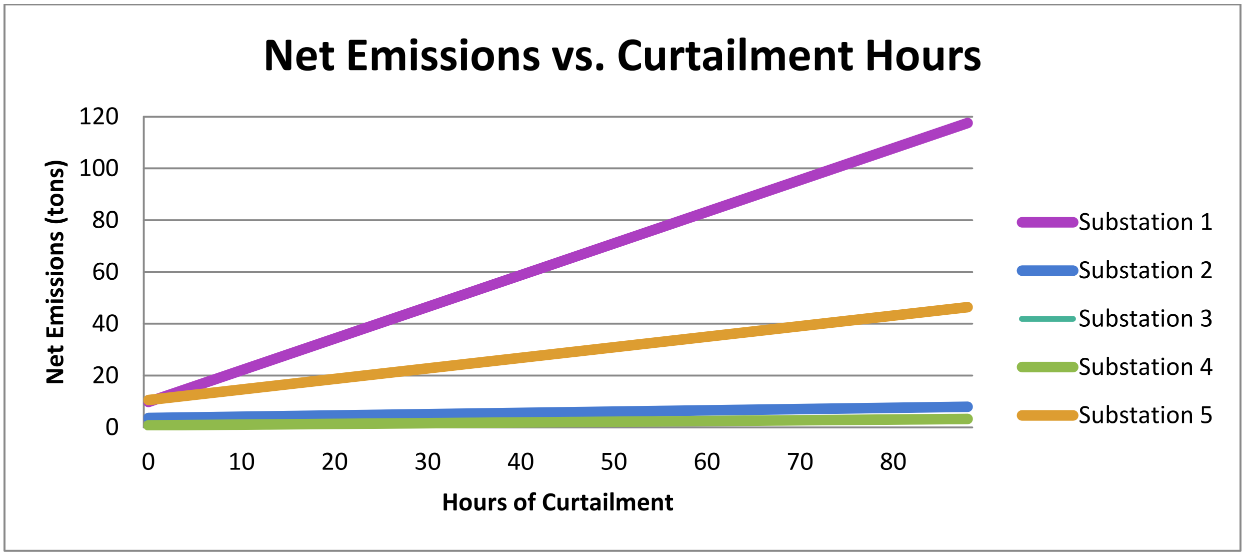
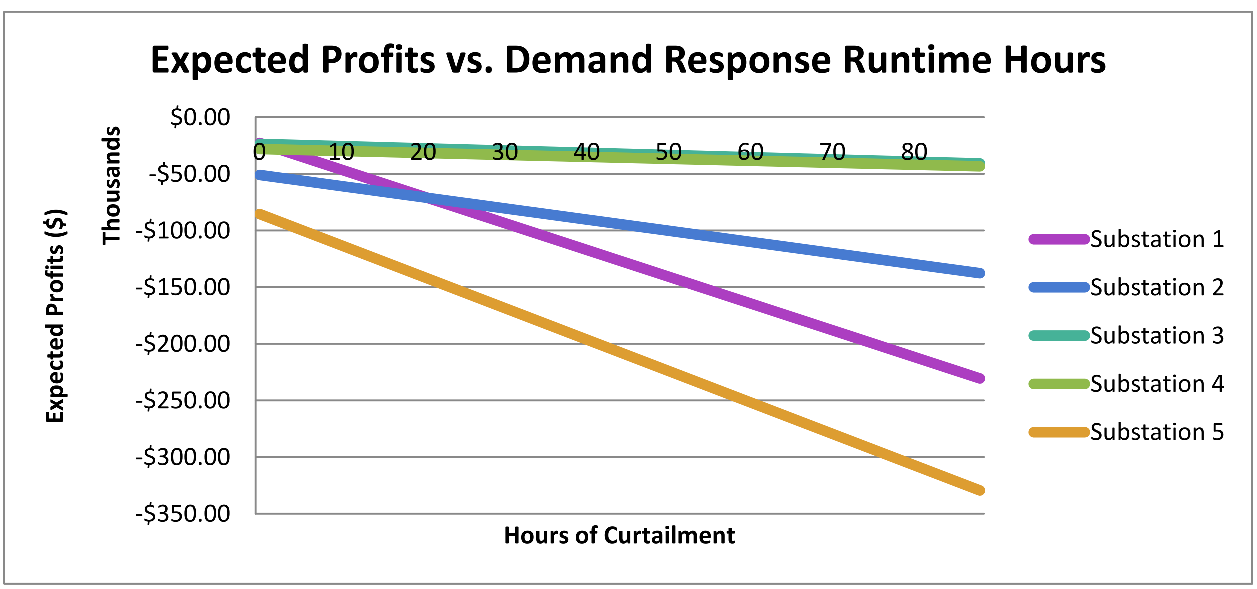


Figure 12. Total emissions from demand response vs. curtailment hours.



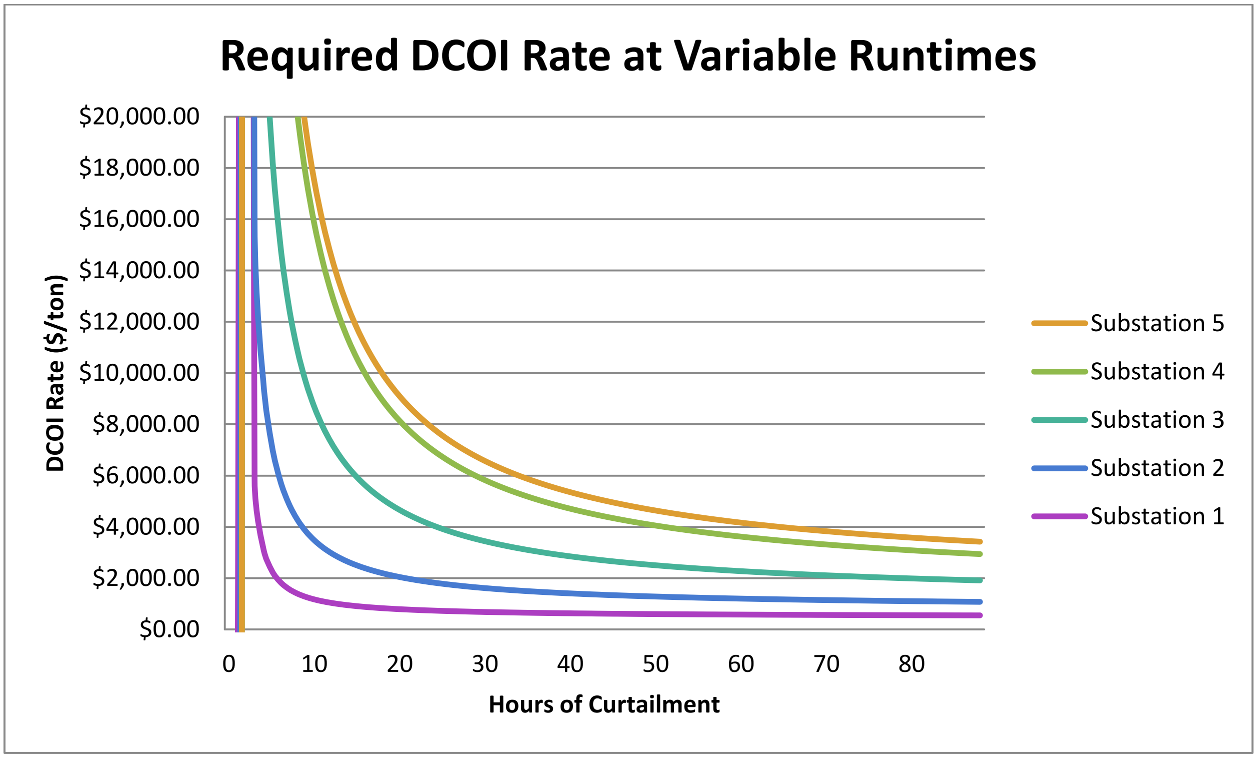
In order to determine the rate at which DCOI credits would be useful, we assumed that coal plants would be the marginal plant in Duke-Energy's loading order (Scenario 2 in our methodology). Based on EPA's eGrid data, coal plants in the North Carolina region have an approximate 2400 lb per MWh. In this case, demand response would result in emission reductions since the grid rate is higher than the emissions rates of Duke generators. The expected profits using this analysis are listed in Figure 13 below.

Figure 13. Expected profits vs. demand response runtime hours.



Given these expected losses, the required DCOI rates to make demand response a revenue-neutral operation are illustrated in Figure 14 below.

Figure 14. Required DCOI rates for revenue neutrality vs. curtailment hours.



For the first two hours, demand response will actually increase emissions (since generator testing takes place when the grid is not strained and has a lower emissions rate). Consequently, it takes two curtailment hours to yield positive emission reductions. Assuming the maximum contracted hours of demand response curtailment hours (and highest emissions reductions), the required DCOI rate ranges from $484.36 to $1,024.24 per ton for each substation. However, the assumption that Duke-Energy will call on the university to curtail for 88 hours is unrealistic. Over the past thirty years, the maximum number of curtailment hours was 29 hours. During this span, the maximum annual demand response time has only amounted to 4.3 hours a year. At 4 hours a year, the required DCOI rate ranges from $3,197 per ton to $23,440 per ton. Given that the maximum amount paid by the DCOI is $40 per ton, the current PowerShare program should not be considered as a carbon offset opportunity.

Conclusion

This study found strong reasons for Duke University Health Systems and Duke University to either cease or decline future participation in Duke Energy's PowerShare program as it is currently structured. While demand response programs have potential to be both economically and environmentally beneficial, DUHS and Duke University fail to benefit in the current PowerShare program due to lower than desired capacity payments and the required re-enrollment in Duke Energy's demand side management fee (DSM). As the program is currently operated, DUHS and Duke University will lose an approximate $20,000 to $350,000 depending on substation and curtailment hours. These large projected losses were found using the study model and are due to the large cost of re-enrolling in Duke Energy's DSM fee to which DUHS and Duke University are currently exempt.

The DSM fee is charged on a per kWh basis and amounts to a significant cost for large consumers of electricity like Duke University (250 GWh per year). Duke University's 250 GWh of energy used each year equates to a large DSM fee that cannot be offset by the potential revenue in capacity credits Duke University may receive as compensation for the PowerShare program. However, through further analysis, this study found PowerShare to be profitable between 0-20 hours of curtailment if the DSM fee is waived. The profits would range from $4,000 to $60,000 annually for each substation. Based on this finding, this study would recommend Duke University to leverage its long standing relationship, large consumption rate, and progressive energy management programs and discuss the potential of waiving the DSM fee with Duke Energy.

Although waiver of the DSM fee would remove a significant barrier to adoption for the PowerShare program, the profits of enrollment are also limited by the curtailment hours. Beyond 20 hours of demand response curtailment, the net revenue would once again benegative due to the low curtailment credits offered by the PowerShare program. These curtailment credits are currently below the average diesel fuel price for North Carolina, allowing each kWh produced by emergency generators to significantly erode the program revenue. Our analysis indicated that in order for the program to be a revenue neutral opportunity for Duke University, the PowerShare curtailment credits would need to increase from \$.10 to \$.26 per kWh. This increased curtailment credit price reflects the true cost of diesel generator produced energy.

In addition to strong economic barriers to participation, our analysis found PowerShare enrollment to be environmentally detrimental from a carbon intensity perspective. The majority of Duke University's eligible emergency generators are diesel (49 out of 50). Duke Energy like other utility providers turn on plants according to a unique "dispatch order" which is based on plant characteristics such as the cost of energy generation, its efficiency, etc. Duke Energy currently uses natural gas plants in peak emergency times, due to the low natural gas prices and natural gas plants flexible ramp rate. Diesel generators are much more carbon intensive than natural gas generators making PowerShare participation actually increase the amount of total carbon emissions. The study found that even if North Carolina's dirtiest coal plants (more carbon intensive than diesel generators) were the last in Duke Energy's loading order, the amount of carbon reductions would be so little relative to the high costs of the program that the credits would need to be in the range of \$484.36 to \$23,330 per ton. Given that the maximum rate DCOI will pay is in the range of \$10-\$40 per ton, it is unrealistic to expect the dramatic increase needed in carbon offset prices to make PowerShare feasible.

Future Recommendations

While this prospectus did not find enrollment in Duke Energy's PowerShare program to be feasible at this time, this will not always be true due to potential changes in the energy sector and perspectives not included in this study. Additional studies can include the indirect impacts of the demand response enrollment. For example, if Duke University could use backup generators to produce its power and offset demand on Duke Energy's grid during peak hours, would this be impactful enough to allow Duke Energy to reduce the operation of pollution intensive plants and create environmental benefits through a cleaner plant portfolio? The study would first have to estimate the current peak usage, establish the Duke Energy loading order, obtain emissions from those plants, and identify the maximum amount of energy Duke University would generate to decrease the use of the dirtiest plants.

Future studies could also explore the impact of natural gas prices and emissions. If natural gas prices dramatically increased, would Duke Energy's plant loading order be impacted enough to make diesel generators significantly better alternatives? If natural gas prices remain low, would Duke University's use of natural gas generators make PowerShare feasible and desirable? This could be a useful study if Duke University is considering a large amount of new generator purchases.

Future expansion on this project could include the rezoning of the generators and their substation connections. This prospectus evaluated the existing generators on Duke University and Duke Medicine campus in their current placement. Since the DSM rider fee application to an entire substation is triggered by the enrollment of any amount of generators on that substation, profit can be maximized by increasing the revenue and decreasing the cost. The revenue can be increased by maximizing the amount of enrolled generators on that substation while cost will remain the same as long as all of these generators are on one substation. Given this cost structure, a study should be conducted to see if rezoning the substations to concentrate the most efficient generators on one substation can produce positive cost-benefit.

The resulting recommendations for program enrollment can also be influenced by the perspective and the objective of the client. While the focus of this prospectus was on carbon dioxide and financial feasibility, another potential study focused on SOx or NOx could identify additional environmental benefits that could justify enrollment in the program.

Finally, this prospectus can be repeated with more detailed analysis of building generator designs. While it is known that oversizing generators is a common industry practice for building designers, the extent of this practice on Duke University should be accurately reflected in the models. This uncertainty and variability in the generator sizing is dealt with in this prospectus through the use of the "reserve ratio" buffer, but more accurate projections could be achieved through tailored measurements for each building generator. This information can be obtained from building designers, engineers, and other knowledgeable maintenance experts such as those in FMD or DUMC.