AN EVALUATION OF THE EXCHANGE OF ENERGY AND VALUE IN NET METERING IN NORTH CAROLINA

A Thesis
by
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Submitted to the Graduate School
at Appalachian State University
in partial fulfillment of the requirements for the degree of
MASTER OF SCIENCE

May 2015
Department of Technology and Environmental Design

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Abstract

AN EVALUATION OF THE EXCHANGE OF ENERGY AND VALUE IN NET METERING IN NORTH CAROLINA

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Net metering as a policy enables customers with solar photovoltaics (PV) to receive retail value for their solar energy. Large-scale evaluations of net metering performed in other states have presented this retail value as a cost to the customer's utility. However, net metering rules in North Carolina often result in net metering customers exporting high-value, peak daytime energy to the utility, and receiving credit for low-value, off-peak nighttime energy in return. The value discrepancy in this exchange has not been present in large-scale evaluations, and my research has developed a method for quantifying the value of the balance of this exchange. My results indicate that utilities often benefit from this exchange, which suggests that net metering of distributed solar PV could be a mutually beneficial arrangement between a customer and his utility.

Acknowledgments

I wish to acknowledge the support and dedication of my graduate committee who assisted me through every step of this process. I wish to thank Jason Hoyle for his comprehensive knowledge of utility policies and practices in North Carolina, and his invaluable assistance in creating the model that enabled this evaluation. I also wish to thank Dr. Raichle, whose objectivity and focus on a final product were behind my every effort in this work, and who was always there to resolve my doubts. Finally, I want to acknowledge the tireless support of Dr. Hoepfl. I am amazed by her dedication, and I would have taken twice as long to write a paper half as good as this without her efforts.

Dedication

This work is dedicated to my mom and dad, Randi and Jeff Neff. The road goes ever on and on, and you have both kept me going on it.

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CHAPTER 1: INTRODUCTION

The surge in installation of solar photovoltaic (PV) systems in the US in the past decade has been eye-catching, and as the successes of this technology enter the limelight so do its controversies. The biggest controversy involving PV is the policy called *net metering*, and this policy has drawn lines between utilities and solar advocacy groups across the nation. As the number of PV systems has increased, so has the volume of the debate. However, due to the complexity of the issue a definitive conclusion resolving the controversy over net metering has not been reached, and the future of net metering is still very much in the balance.

Net metering is a policy that allows customer-generators to exchange excess electricity they export onto the electric grid for credits to offset electricity that the independent producers import or draw from the grid. Net metering is particularly valuable for owners of PV or wind systems because it allows them to “use” all of the electricity their systems generate without having to invest in batteries, and at the same time ensures they have access to uninterrupted supplies of electricity. In effect, the grid acts as a battery to these customers, allowing them to bank electricity for later use. This is where the controversy begins.

Net metering solar PV systems can be best understood as operating in three different “states” or conditions, as explained by Beach, McGuire, and Crossborder Energy in their 2013 evaluation of net metering in California (Beach, McGuire, & Crossborder Energy, 2013, p. 9). The first state is when the sun isn't shining and the customer is solely consuming grid energy. In this state, the customer is acting like any other retail customer. The second state is when the sun is up and there is PV energy production, but not enough to serve all of the customer's electrical demand. In this state, the PV system is lowering the customer's overall demand, but there is still some grid energy flowing to the customer. The PV system is acting here like an energy efficiency device, lowering the overall amount of grid energy that is consumed. The final state is when the PV system is producing more energy than the customer is using at that moment, and the excess electricity is exported onto the grid. In this scenario, that electricity flows to other users on the grid, which they consume and pay for just like any other grid electricity, and the customer-generator receives an energy credit to be used to offset future grid electricity imports (Figure 1).

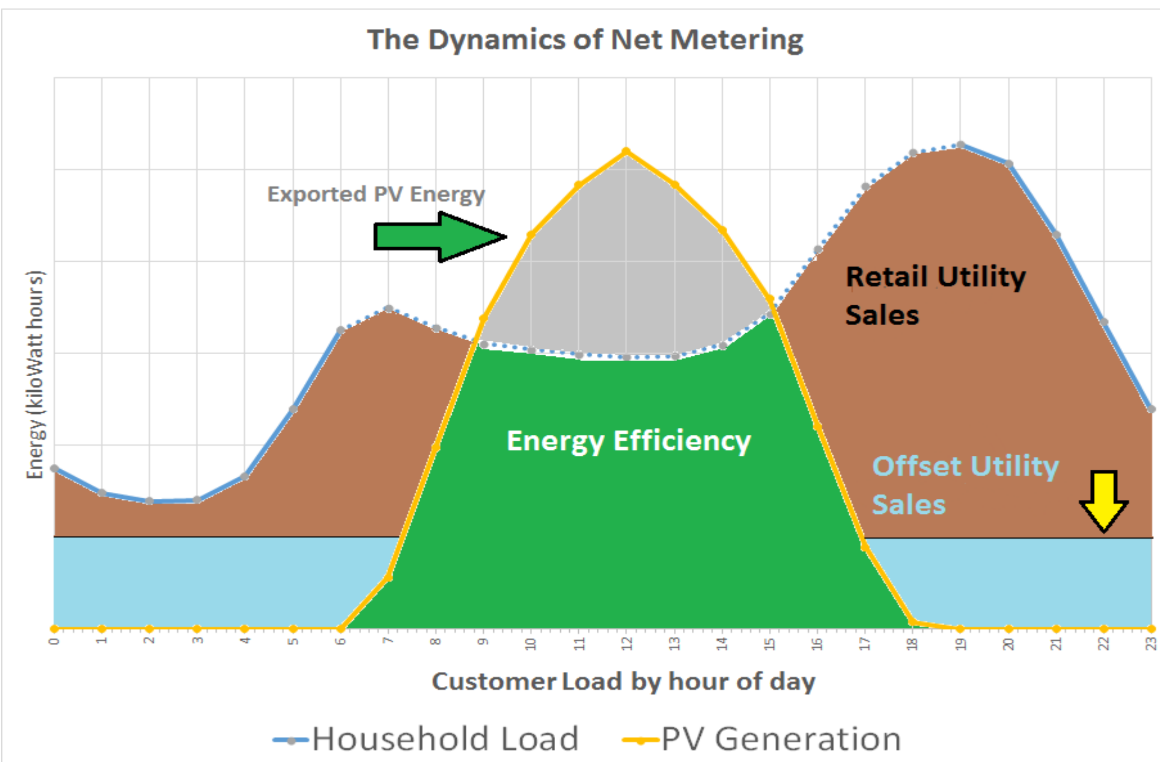


Figure 1. An average daily profile of electricity demand (blue line) and solar PV generation (yellow line) for a net metering customer. Excess PV energy is used to offset grid energy consumption.

It is this third state that has caused so much debate over net metering. Utilities claim that by crediting net metering customers at the retail rate for their exported energy, the cost of grid services such as transmission and distribution of that credited energy is not paid for and the net metering customer gets an unnecessary and unearned benefit in the difference between the avoided generation cost and the retail rate of electricity. The overall effect is that the customer benefits twice, at the expense of other customers; hence the term "cross-subsidization."

From the utility's standpoint, the problem is that there are more costs in delivering electricity to customers than just what it takes to produce the energy. Although a solar panel can produce energy for "free," a net metering customer still relies on utility power lines and substations to move that energy around, and to deliver electricity to their home when their solar panels are not producing electricity. Retail rates usually represent the cost of transmission, distribution, and other fixed costs, as well as the variable cost of generating energy. In fact, utilities routinely calculate the costs they avoid when small power producers supply electricity to the grid, called the avoided cost, and are required by federal legislation to offer to pay qualifying facilities (or small power producers) a price equal to the avoided cost for energy these small producers supply to the utility. The discrepancy between the avoided costs and the costs of maintaining the grid is at the root of utilities' arguments about customer-owned net-metered PV generation.

Cross-subsidization is an issue inherent to net metering, but it is not the only argument that utilities have used to advocate for additional charges on net metering systems. Utilities have also argued that customer-owned solar PV leads to lost revenues. The argument is that, as solar PV becomes more affordable and more people invest in self-generation, the amount of revenue that a utility receives will diminish, while the fixed costs will stay the same. This will lead to an increase in utility rates, which will make solar PV even more affordable, and fuel the trend towards solar PV self-generation and further decreasing utility revenues. This argument was voiced perhaps most famously in the Edison Electric Institute's publication called *Disruptive Challenges*, which sparked a wave of utility pressure on net metering programs. The fear is that customer-owned solar PV generation will make grid electricity unaffordable for those with limited financial means, and drive a gap between solar PV owners and everyone else (Edison Electric Institute, 2013).

These claims have been examined across the country. The Vermont legislature ordered its Public Service Department to look into the "existence and degree" of cross-subsidies in net metering in its 2014 evaluation of the practice (Public Service Department of Vermont, 2014, p. 2), and similar legislative directives were issued in Nevada in 2013, California in 2012, and in Arizona, Utah, and Hawaii (Durkay, 2014). Minnesota recently completed a value-of-solar evaluation that looked at solar energy generation in general rather than just at net metering (Farrell, 2014). Numerous independent parties have published generalized articles on the costs and benefits of net metering, including Richard Perez of the University of Albany and the Interstate Renewable Energy Council (IREC) (Perez, Zweibel, & Hoff, 2011; Keyes & Wiedman, 2012). An evaluation of distributed solar PV generation in North Carolina was also recently completed, and this evaluation included lost revenues in its tally of the costs of distributed solar generation to NC (Beach & McGuire, 2013).

The distinction between cross-subsidization and lost revenues is an important one. Lost revenues are not specific to customer-owned solar PV in general, but cross-subsidization specifically applies to net metering. The difference is that not everyone who owns solar panels net meters, and not all energy produced by a net-metered system is exported onto the grid. Cross-subsidization attributable to net metering only applies to *exported* energy that is used to offset energy that is imported at a later time, while lost revenues can derive from any amount of solar PV generation. Although net metering makes solar PV more attractive to homeowners, one does not have to net meter in order to invest in solar PV, and in fact one's right to generate power for one's own consumption (i.e., not for grid export) was established by the Public Utilities Regulatory Policies Act (PURPA) of 1978, one of the only guiding federal legislative acts pertaining to customer-owned renewable energy.

The decision of whether or not to recoup the costs associated with net metering customers' use of grid services is not a light one. In California, the costs of those grid services for net-metered PV customers have been estimated at $2.2 billion dollars per year (Energy and Environmental Economics, Inc., 2013). Of that amount, only $700 million is attributable to energy exported onto the grid—the rest comes from PV energy that is consumed at the customer's location. Indeed, how to account for such lost revenues is a decision that bears much consequence for utilities and for solar PV owners.

Whether net metering policy changes should be driven by the effects of lost revenues, or cross-subsidization, or both, is a matter for regulatory and legislative bodies to debate. They have several competing mandates to balance; in North Carolina, the North Carolina Utilities Commission (NCUC) is legislatively charged with ensuring utility rates are fair and as low as possible, an interest that must be balanced against the state's legislative commitment to renewable energy and federal guiding legislation such as PURPA.

However, it is impossible to make such a balanced decision about cross-subsidization without knowing how much of a problem it actually represents. Although many methods and estimates have been presented before the NCUC in its investigation into net metering, none have proven to be satisfactory, and the NCUC has yet to determine the extent and degree of cross-subsidization in net metering (In the Matter of Investigation of Net Metering, 2009). Furthermore, there are very few studies that focus solely on the exchange of exported PV energy between customer and utility for the NCUC to look to for guidance.

This research focuses on exported PV energy in net-metered systems and the values exchanged between customer and utility because of that energy, at both the wholesale and retail level. At both levels, there are opportunities for the exchange of value to be an unequal one. At the retail level, time-of-use (TOU) pricing means that electricity is valued differently at different times of day. In North Carolina, TOU pricing splits the day into two prices, peak hours and off-peak hours. Peak hours are priced higher than off-peak hours, and there are more off-peak hours in a year than peak hours. This, and some details of North Carolina's net metering policy, means that the opportunity exists for a customer to export energy during peak hours, but to have that energy credit used during off-peak hours. In this circumstance, the utility benefits by the difference between the peak price of electricity and the off-peak price. This same mismatch cannot be flipped, because under North Carolina law a net metering customer can never use an off-peak energy credit to offset imports of peak energy.

North Carolina's net metering policy also mandates that excess net metering credits can be rolled over from month to month, but expire at the end of the utility year, which is May 31st. This means that summer peak credits, which are the most valuable from a retail standpoint, can be offset against the less valuable fall or winter off-peak consumption. It also means that situations exist where exported PV energy does not offset grid energy consumption, but instead is forfeited to the utility. In such cases, the utility benefits by selling those forfeited kilowatt-hours at the full retail price.

There are also opportunities for unequal exchanges at the wholesale level. The cost of generating electricity varies with supply and demand. During times of high demand, the cost of generating electricity goes up as infrequently used power plants with low construction costs but high operating costs are dispatched to provide power. Electricity demand follows somewhat predictable patterns over the day and over the year. Under these conditions, it is possible for a net metering customer to preferentially export energy at times of high demand, providing high-value electricity, and then use his credits to offset low-value electricity consumed at times of low demand. It is also possible for the reverse to be true. However, multiple studies have shown that the wholesale cost of electricity generally tends to be highest during sunny summer days, which is exactly when solar PV systems are producing the most electricity (Borenstein, 2008; Hummon, Denholm, & Margolis, 2013).

This research focuses on closing the gap in knowledge on the mechanics of cross-subsidization in net metering by looking closely at the circumstances that drive the exchange of electricity and value between a net metering customer and a utility. This research looks more closely at those circumstances to understand what, if any, benefit a utility derives from uneven exchanges, and estimates whether the exchange of value between a customer and a utility is a net benefit or cost to the utility.

Statement of the Problem

Net metering is an exchange of energy and of value. The value that is exchanged between customer and utility is represented by the retail rate of the electricity exported and credited, and the wholesale cost of the energy exported and imported. Much of the research and evaluations conducted to date have focused on modeling future scenarios of net metering, instead of using actual data. Because the value of net metering is a delicate interplay between solar resource availability, customer energy demand, and the wholesale and retail price of electricity for a utility, it is important to use actual data to evaluate costs and benefits. This research develops a methodology to use actual data to determine the balance of the costs and benefits a utility derives from its exchange of energy with a net metering customer.

Research Questions

This study sought to test the extent or inherence of cross-subsidization in net metering. Cross-subsidization is defined here as the unequal exchange of value between a net metering customer and the utility. The extent sought to test this through one primary research hypothesis (with the corollary null hypothesis):

H_1: The exchange of retail and wholesale value between a net-metered PV customer and the utility results in a net benefit for the electric utility.

$H_{0:}$ The exchange of retail and wholesale value between a net-metered PV customer and the utility has no benefit for the electric utility.

The overall net value of a net-metered PV system to an electric utility is dependent on several factors. Therefore, the following research questions underpin the research hypothesis:

RQ1: Based on the modeled data, what is the relationship between energy produced and energy exported from net-metered PV systems in the Duke Energy Carolinas (DEC) service area?

RQ2: What information do these data provide about the *amount* and *timing* of availability of the PV system's energy exports, on average?

RQ3: What do these data suggest about the costs and/or benefits, and under what conditions or circumstances, of net-metered PV systems to the DEC utility?

Definition of Terms

Avoided costs: the calculated average cost of generating electricity for a utility.

Capacity factor: the percentage of an energy-generating unit's nameplate capacity that is available for energy production at a certain time.

Coincident use: amount of PV energy that is directly used onsite by the net metering customer at the time the PV energy is generated; this portion of PV energy is not exported.

Dispatchable generator: an electricity generator whose capacity can be called for at any time of the day. Wind and solar PV are not dispatchable generators without energy storage.

Distributed generation: generation resources that are located close to customer load, such as residential solar PV systems.

Exported energy: generated PV energy in excess of customer electricity demand that is delivered to the grid in exchange for credit against future electricity use.

Imported energy: total amount of customer's grid electrical usage.

Locational marginal price (LMP): a market-based wholesale electricity price that fluctuates with electricity supply and demand. Represents the marginal cost of procuring electricity in a wholesale market at a given time and location.

PV: solar photovoltaics. The technology that converts solar irradiance into electricity.

Offset energy: portion of customer's grid electrical usage that is offset by exported energy.

Solar fraction: the ratio of PV energy generated to a customer's total energy consumption over a given period of time, expressed as a percentage. For example, if a customer who consumes 100 kWh over a year installs a PV system that is expected to generate 50 kWh during the year, the solar fraction is 50%.

Time-of-use (TOU) rates: a retail rate that charges different prices for electricity at different times of the day and year.

Limitations of the Study

This study attempted to calculate cross-subsidization by using measured data of customer electricity demand, solar PV generation, and utility wholesale costs. However, it was not possible to acquire all of this data for Charlotte, NC, the area chosen for the study. The utility serving the study area, Duke Energy Carolinas (DEC), is a publicly regulated, vertically integrated, investor-owned utility, and real-time data about its generation profile or wholesale costs are not available. My advisors and I attempted to acquire this data from DEC without success. However, in place of this desired data set, I used data from the PJM Interconnection market for Dominion Resources (DOM), a utility operating in a competitive wholesale market, and a close proxy to DEC. DOM's service area and customer base is of similar size to DEC's, and is close in distance and in climate (Duke Energy Corporation, 2014; Dominion Resources, Inc., 2014). The lack of actual wholesale costs from DEC means that the results of this study cannot be taken as a definitive calculation of cross-subsidization.

I also did not have access to actual customer electricity demand data from Charlotte, NC. DEC policies regarding customer privacy agreements prevented me from acquiring the data from DEC. Customer electricity demand was instead estimated using a model developed by the National Renewable Energy Lab (NREL) and the US Department of Energy (USDOE). A major limitation of this approach is that the model used TMY2 weather data instead of actual measured weather data, so the customer demand profile did not respond to abnormal or extreme weather patterns that may have occurred during the period under study. Also, the customer demand profile did not respond to economic conditions. The United States Energy Information Agency (USEIA) found that the so-called Great Recession had a significant impact on average household electricity consumption and on energy prices, so the consumer energy use results calculated for those years may not reflect normal use trends (McManmon & Brown, 2013).

The lack of a correlation between actual weather and customer load is a problem because I used measured data to calculate solar PV generation potential. Thus, the amount of solar PV changed with the weather in the model, as did the wholesale cost of electricity, but the customer load did not. I accommodated this issue by weatherizing the customer usage data using linear regressions based on the modeled heating and cooling loads. The methodology I used was designed for all three data sets to be dependent on the same weather data, and to vary according to the same weather trends. Although the weatherized model will be as useful and accurate as any modeled scenario can be, using real customer usage data might provide better insights into net metering customers' habits.

The applicability of my findings to future scenarios is also uncertain. Of the data that I used, only solar PV generation is likely to produce similar results in the future. Customer energy usage, the wholesale cost of electricity, even the retail rate of electricity, are all dynamic values that change with weather, economic trends, or political actions, such as the U.S. Environmental Protection Agency's new rules regarding emissions standards for power plants. The trends that I have found in these data sets are likely to have different magnitudes in the future, and may be different altogether. For example, large penetrations of PV power may flip the wholesale cost trend such that daytime energy has the lowest wholesale cost. Although the results I have derived from these data may not hold true in the future, other authors should be aware of their importance and factor them into their own analyses.

Lastly, the methods of this evaluation compile hourly results over a five year study period to calculate the bulk exchange of value in net metering. This bulk method fails to fully account for the value distribution of wholesale electricity costs; for example, while 90% of the wholesale costs in this study were under $0.10/kWh, the highest cost was $1/kWh, a 1000% increase over the bulk of the data. These price spikes have an outsized effect on utility operating costs and strategic generation capacity plans, and future studies should give these costs special attention.

Significance of the Study

The lack of synchronicity between the data sets I used for this analysis means that this study is much more an estimation of cross-subsidization than an empirical calculation. However, there are significant lessons that can be learned from this research and evaluated using more appropriate data. Furthermore, although this study largely relied on proxy or modeled data sets, the inadequacies of the data were averaged out by the length of the study period. This means that any broad trends that were uncovered in the inequality of net metering exchanges in this study point to areas that should be focused on in future studies.

Furthermore, some of the values examined in this research have not been calculated in other studies. For example, I have not found any other published studies that looked at the retail exchange inequality in TOU net-metered systems. Also, the utilities in North Carolina must publish how many kilowatt-hours per year are forfeited to them by net metering customers, but they do not have to publish what the retail value of those kilowatt-hours are. Any accounting of cross-subsidization should include the full value of those kilowatt-hours, since they were donated to the utility and then sold to a customer at the full retail rate. This study attempted to uncover the value of that exchange, information critical to a better understanding of cross-subsidization effects.

The trends identified and methodologies used in this research should be of particular interest to stakeholders in the net metering debate in North Carolina. That includes Duke Energy Corporation, Dominion Resources, Inc., the NCUC, solar energy advocacy groups, and the citizens of North Carolina. This research may help to indicate factors and variables for policy makers to include in any process that seeks to address cross-subsidization in net metering.

CHAPTER 2: REVIEW OF LITERATURE

The common methods for evaluating the value of distributed solar PV resources, as presented in Chapter 1, are wide-ranging and far-reaching, and investigate measurable economic and physical costs of distributed generation. A common thread in the literature has been the relationship between solar PV energy generation and the market price of electricity generation. The published research has investigated the extent of the relationship between solar PV generation and market prices, as well as the possible market implications of high penetrations of solar PV. There have also been numerous large-scale evaluations of net metering conducted in various states, all of which stand as a contrast to the methods and focus of my research.

The contrast between my research and large-scale evaluations is that those studies include lost revenues due to PV generation in their calculations, while mine does not. For example, all three major evaluations of net metering in California included the cost of lost revenues in their conclusions (Beach, McGuire, & Crossborder Energy, 2013; Darghouth, Barbose, & Wiser, 2010; Energy and Environmental Economics, Inc., 2013).

All three of those studies also included the avoided wholesale costs due to PV energy in their valuation. Darghouth, Barbose, and Wiser (2010) used the Market Price Referent, which is an approximation of hourly wholesale costs, to value exported PV energy, but that price was based solely on generation costs of combined-cycle gas turbines rather than on the full utility generation mix. Energy Environment and Economics, Inc. (E3) also calculated the value of PV exports using their own avoided costs model, which did use hourly market price data, but their projections were based on Typical Meteorological Years (TMY) and did not account for weather and price surges (Energy Environment and Economics, Inc. [E3], 2013). Beach, McGuire, and Crossborder Energy (2013) also used the avoided costs model developed by E3.

E3 (2013) and Darghouth et al. (2010) found that the costs of net metering increased with the proportion of energy that was exported. Beach, McGuire, and Crossborder Energy (2013) found the opposite to be true, where the benefits of net metering increased with the PV system's proportion to overall customer energy usage, presumably because the more energy that a PV system exports, the less renewable energy a utility has to buy at a premium. However, the results of these evaluations are not directly relatable to this study because all three evaluations included bill savings as a cost that net metering incurs upon a utility. To illustrate the effect that including bill savings had in these studies, consider that all three found that the costs of net metering were most severe in the Pacific Gas & Electric territory because of a steeply-tiered energy rate. This steep rate amplified the bill savings of net metering customers because the net metering system shifted the customer into much lower-priced energy blocks. As Beach, McGuire, and Crossborder Energy stated, a PV system in this rate "principally offsets more expensive, higher-tier usage" (Beach, McGuire, & Crossborder Energy, 2013, p. 24). This effect is an artifact of the rate design rather than of net metering, and along with the reasons covered in Chapter 1, shows why my study does not include bill savings or lost revenues as a cost inherent to net metering since these effects would result from any distributed generation that served some part of a customer's load, energy efficiency, or any other customer-side intervention that reduced the customer's consumption of grid energy.

Outside of the community of researchers interested in net metering, the complementary relationship between solar PV generation and market prices has received significant attention. The idea that solar PV could align well with times of high system demand was voiced as long ago as 1994 (Haas, 1994; Perez, Seals, & Stewart, 1994). At that time, there was not a great deal of PV systems available to experimentally confirm a correlation between peak system load and solar PV availability, which meant some of the earliest research used satellite insolation data to investigate the relationship between the two (Perez, Seals, & Stewart, 1993; Perez, Letendre, & Herig, 2001). These early studies indicated that the solar generation generally coincided with utility loads, according to trends in solar insolation and cloud cover.

As PV adoption increased and some cities acquired significant penetrations of PV capacity, researchers were able to use actual production data to test the hypothesis. Tim Meyer and Joachim Luther's analysis in Germany showed that there was a good correlation between PV generation and spot market prices, especially during the summer (Meyer & Luther, 2004). This analysis used actual PV production measured at 16 sites across Germany, and compared it to spot-market prices on the European Power Exchange and the Amsterdam Power Exchange. A researcher in Canada during the same time period used electricity price data from the Alberta Electric System Operator and the Independent Electricity Market Operator of Ontario and solar radiation data measured at weather stations in Calgary and Guelph. This research found that solar PV could provide up to 74% of the peak summer demand, and that all electricity demand in the 90th percentile between April and

July was during daylight hours (Rowlands, 2005). Other researchers in Canada focused on the benefits solar PV has on transmission and distribution costs due to its generation being close to its load (Brown & Rowlands, 2009).

However, researchers have discovered that the relationship between PV, energy demand, and energy prices are not perfect. Often, utility system demand peaks are in the late afternoon, when the solar resource is waning (Denholm & Margolis, 2007). This effect is exacerbated in the winter, when system demand becomes less coincident with levels of solar irradiance, and in the spring and fall when overall system demand is at its lowest (Denholm, Kuss, & Margolis, 2013). Orienting a solar PV array to the west to more fully align with peak electricity demand has been shown to increase the market value of the PV system by up to 5% (Hummon, Denholm, & Margolis, 2013).

As the cost of PV falls and its penetration in the electric power markets increases, researchers have been able to study the real-world interaction between renewable energy systems and market prices. One interesting effect is that renewable energy has actually lowered the market price of electricity due to the merit-order effect. Many deregulated markets in the US and Europe use merit-order ranking to decide how to meet the electrical demand of their system. Merit-order ranking positions available power sources based on their *marginal* cost of producing power; that is, how much it would cost to produce one more unit of electricity. This margin is generally dependent on the fuel costs of an electricity source, and because solar PV in operation has zero fuel costs, it is always preferred on the market. Researchers in Germany found that large penetrations of zero-cost energy had a merit-order effect of 4.98 billion € in 2006 (Sensfuss, Ragwitz, & Genoese, 2008). A similar effect was found in Australia (McConnell, et al., 2013). The effect is larger in Europe because there is a CO_2 trading system enmeshed with the European electricity market, but the effect showed the greatest sensitivity to rising fuel prices. Much of this effect was a function of PV energy reducing demand during times of high fuel prices.

The nascence of large penetrations of PV generation in the US has led to preliminary evidence of the impact of renewable resources in US energy markets. The USEIA published data from California Independent System Operator (CAISO), the entity that coordinates the electricity delivery system for most of California, which indicated that significant reductions in net demand could be attributed to renewable energy (Bredehoeft & Krall, 2014). An illustration of these findings is presented in Figure 2. It is important to note that this data combined solar and wind energy, but the effect of solar PV on system demand can be clearly seen. The relationship between summer demand and solar PV in California was predicted as long ago as 2008 (Borenstein, 2008). Although an accurate estimate of the merit-order effect has not been produced for the US, preliminary research suggests a relationship between PV production and energy prices (Darghouth, Barbose, & Wiser, 2014). NREL has devoted some of its research capacity towards investigating the relationship between renewable energy and energy markets (Ela, Milligan, Bloom, Botterud, Townsend, & Levin, 2014). Preliminary research suggested that the Cape Wind project in New England could have price-suppression impacts of up to $185 million per year (Charles River Associates, 2010).

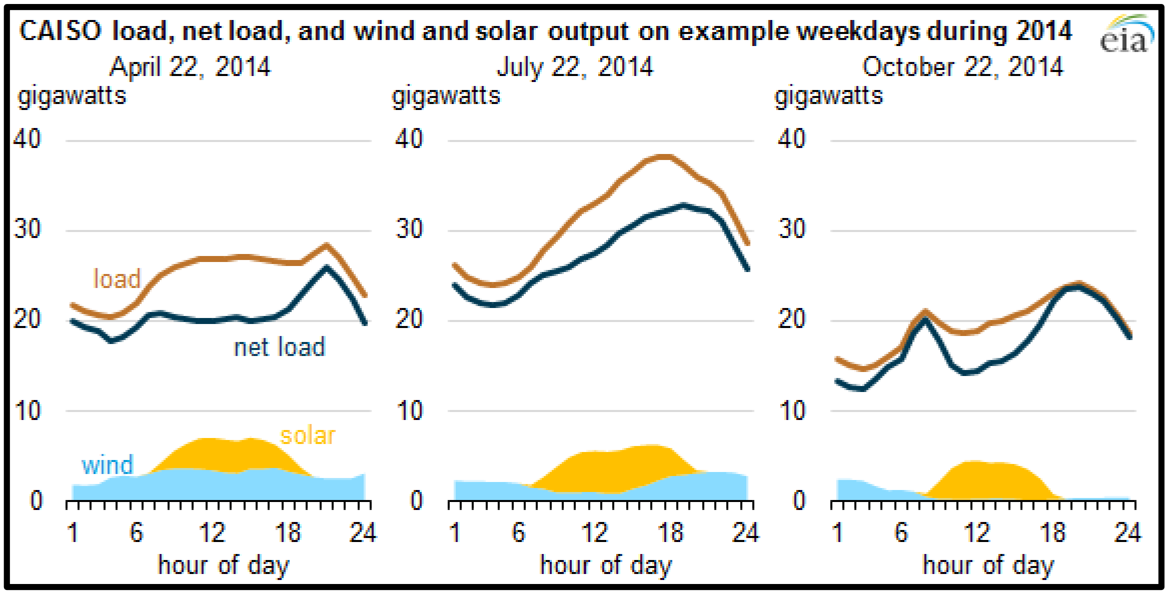


Figure 2. CAISO data reflecting effect of renewables on net load. Data from the CAISO indicates that renewable energy in California is having a significant effect on the net load that must be met with fossil fuel production (Bredehoft & Krall, 2014).

The focus of this research is on the exchange of value between exported PV energy from a net metering system and the offset grid energy. The utility will benefit if that PV energy is higher *on average* than the offset energy, even if the PV energy does not align exactly with the wholesale generation costs. The previous studies that have examined this relationship suggest a strong possibility that PV energy coincides with higher-than-average wholesale energy market prices.

CHAPTER 3: METHODOLOGY

The purpose of this research project was to examine the net flow of value between a net-metered customer generating electricity via solar PV and the serving utility. Electricity is a value to the utility at the retail and at the wholesale level, and that value changes on an hourly basis. This methodology uses time-coincident data to investigate whether the net flow of that value is an overall benefit to the utility, or a cost.

As stated above, the retail and wholesale values of electricity are variable over time, so it is necessary to have data from coincident time periods that was collected in similar time intervals. I used hourly data sets, although this methodology could be done with sub-hourly data if that were available. Hourly data sets were the best available data source in my research.

The goal of the research was to identify how many dollars DEC gains or loses per kilowatt-hour of electricity exported from a net-metered PV system. To derive this value, I used time-coincident datasets of PV power generation, customer electricity usage, and utility wholesale generation cost, as well as retail rate information from DEC to determine what the flow of electricity and value was between a net metering customer and DEC in the utility years starting June 1, 2005 and ending on May 31, 2010. The following sections describe how I acquired the data, and what analytical techniques I used to derive the net-metered PV system's value.

Methodology, Part 1: Evaluation Techniques

This research focused on the exchange of energy and value between a net metering customer and DEC. There are several elements that define this exchange and that must be represented through data. First, net metering is, at its heart, a balance between a customer's energy usage (data set 1) and his solar PV energy generation (data set 2). These two data sets (customer energy use and solar PV generation) describe the customer's energy dynamics. To describe the exchange of value with the utility, I used wholesale generation costs (data set 3) and DEC's Residential Service Time-of-Use (RST) rate schedule (data set 4), which defines the retail price of electricity within the DEC service area according to peak and off-peak electricity rates. I created these four data sets in an hourly, time-synchronous Excel model and analyzed the interactions.

Before summarizing the efforts that went into creating the data sets for this evaluation, which were substantial, I want to describe the mechanics of the model that I used. This model can be driven with any time-synchronous suite of the above four data sets, but it has significant complexity that I wish to dive into before describing where the data came from.

Exchange of Energy

The first step in this method was to establish when a customer is a *net consumer* of energy from the grid, and when he is a *net exporter* of energy. Identifying these times allows one to analyze the coincident costs that are avoided by, or incurred on, the utility. This should be a simple interaction; if a customer's energy demand is greater than his PV generation, then he is a net consumer, and if not, he's a net exporter. However, the experimental design, which tested many different PV orientations and solar fractions, introduced complications into the interaction. I accommodated this complexity by using capacity factors for each PV orientation. Capacity factor is the percentage of a resource's generation capacity that is available in that hour, and normally ranges from 0 – 100%.

To calculate a customer's energy flow, I compared the customer's energy use with his PV resource, which was calculated by multiplying the capacity factor by the PV array size, in kilowatts, being tested. This interaction between the data sets created three metrics: (a) the energy a customer imported from the grid, (b) the energy a customer used directly from the PV system, and (c) the energy a customer exported onto the grid (Figure 3). These three metrics describe the universe of the exchange of energy between a net metering customer and the utility.

My PV model is useful in producing arrays of different sized kilowatt capacities. However, my experimental designs varies the sizes of PV arrays by their *solar fraction*. While kilowatt-capacity will tell how much energy the PV system generates over the five year study period, the solar fraction tells how much of *the customer's energy usage* the PV array will account for over the same period. I have used solar fraction in order to compare two customer use profiles on a level ground, even though one uses far more electricity than the other. For example, in my study, a customer using gas heat has a five-year electricity usage of around 70,000 kWh, and the customer using electrical heat uses 126,000 kWh. If both customers owned a five kW net-metered PV system, the one with gas heat would have a solar fraction of 50%, and the one with electric heat would have a solar fraction of 25%.

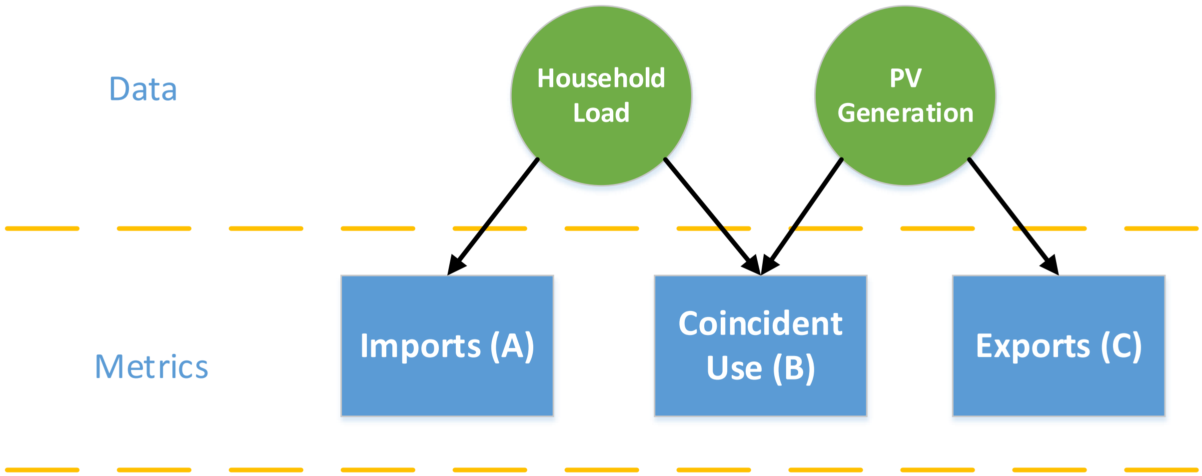


Figure 3. The three metrics of the exchange of energy. These three metrics are calculated using customer usage and PV generation data, and describe the possible flows of electricity in a net-metered system

Exchange of Value

Net metering is not only an exchange of electricity, but also an exchange of value. Electricity has a generation cost associated with it that represents how often a generation unit is used, how much electricity is needed by the grid right then, how much it cost to build the generating capacity, and how much the fuel used to generate electricity costs. In general, the wholesale generation cost refers to the variable costs of electricity generation, such as the fuel, while the retail rate takes into account the fixed costs, such as how much it cost to build the generating unit. For net metering customers under DEC's RST rate, there is also a demand charge of $1.48/kW per month, which reflects the fixed costs associated with generating capacity.

To properly cover the values that are exchanged in a net metering scenario, an evaluation of the exchange of value between a net metering customer and the utility must have data that represent the wholesale and retail values of electricity, and these data must be aligned with the metrics in Figure 3 to calculate the flows of value.

I used a four-step process to calculate the retail value of each energy metric (Figure 4). The first two steps describe the physical processes of net metering; that is, whether a customer is pulling energy from the grid or pushing energy out to it. The third step uses the RST rate schedule to determine in what rate class those energy imports or exports occur, so that the exchange of energy and value can follow the North Carolina TOU exchange rules. These exchange rules are crucial in determining the value of the energy, and the retail value in particular.

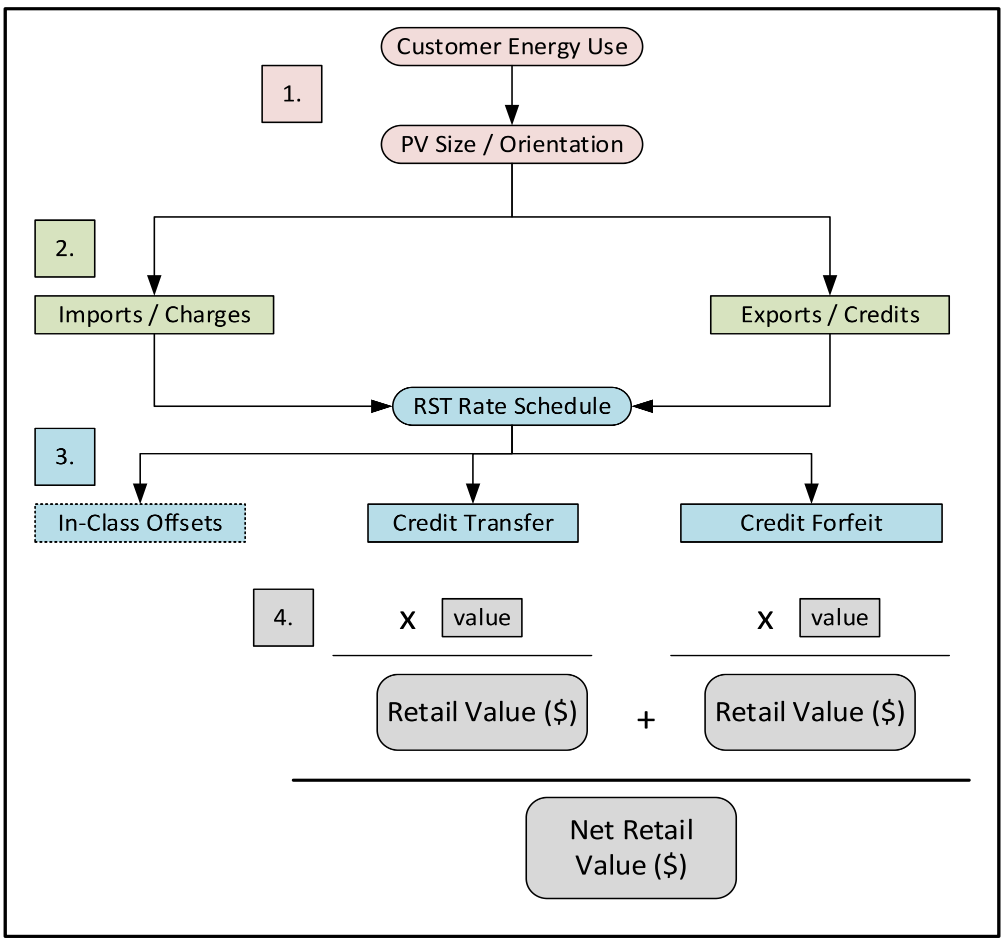


Figure 4. The four step process to calculate retail value. Step 1 represents the data sets that describe the physical energy processes. Step 2 represents the metrics that were referenced in Figure 3, minus coincident use, which does not enter into the exchange of value or energy. Step 3 represents the TOU rate, which dictates which exports can offset which imports. Step 4 represents the valuation of this exchange.

There are two methods of calculating Step 4, which are dictated by which exchange of value is being calculated. It is essential to remember that this is an *exchange*, and one which may be unequal. The exchange of retail value in a TOU system, in particular, is set up to be unequal, due to the rules governing peak and off-peak credits. This exchange is described further in the next section.

Exchange of retail value.

In North Carolina, net metering customers have a choice of rate schedule. Currently, there is a significant difference between these choices. Customers can choose a TOU rate and keep the renewable energy credits (RECs) that their system produces, or they can choose a flat retail rate and relinquish all RECs to the utility. DEC's residential net metering customers can choose between two time-of-use rates (RST and RT), as well as a flat rate (RS). This research focused on customers under the RST rate. All of DEC's rate schedules are available for download at their website (http://www.duke-energy.com/rates/north-carolina.asp), and also are filed with the NCUC.

I used the RST rate schedule information to build an hourly profile of the retail rate of electricity for each hour of the year. DEC's RST rate is a TOU-energy rate, which means that a customer using this rate is charged a different rate for kilowatt-hours consumed at different times of the day and the year. The RST rate contains an off-peak energy charge, and a peak energy charge that changes with the season. In the months of June through September, energy usage on weekdays between 12:00 noon and 6:00 p.m. is charged at the peak energy rate, while energy used during all other hours and weekends and holidays is charged at the off-peak rate. In the months of October through May, the peak energy hours change such that energy used between 7:00 a.m. and 1:00 p.m. is charged at the peak energy rate. The peak energy rate between October and May is also slightly lower than the rate between June and September. Table 1 contains the rate information and Table 2 shows the hourly distribution of peak and off-peak hours for the summer and winter months.

Table 1. *Duke Energy Carolina's RST Rate Schedule*

	Monthly Period	Peak Hours	Peak Energy Rate	Off-Peak Energy Rate
Summer Months	6/1 – 9/30	12:00 p.m – 6:00 p.m	14.7509 ¢/kWh	7.0304 ¢/kWh
Winter Months	10/1 – 5/31	7:00 a.m. – 1:00 p.m.	13.3437 ¢/kWh	7.0304 ¢/kWh

Note: Reproduced from DEC's RST rate schedule (Duke Energy Carolinas, LLC, 2014b).

Table 2. *Hourly Distribution of Peak and Off-Peak Hours for RST Rate Schedule*

	Peak Energy Hours	Off-Peak Energy Hours
Summer Months	616	2,312
Winter Months	1,211	4,621

DEC's net metering rider (Schedule NM) outlines the precise mechanics of net metering in North Carolina. This research focuses on how credits can be applied to imported electricity, and there are very specific rules for that in North Carolina. Under a TOU rate, credits are first applied to charges in the same rate class as the credit. If after this there are peak credits remaining, those credits are applied to off-peak charges. If there are still excess credits once all charges have been credited, the remaining credits can roll over to the next month and be included in that month's tally. However, at no time may off-peak credits be applied to on-peak charges (B. Hinton, personal communication, February 16, 2015). The excess monthly credits can roll forward from month to month until the end of the utility year, when any remaining excess is forfeited to the utility. Currently, the utility year ends on May

31. The customer is not compensated for the kilowatt-hours that are forfeited to the utility at the end of the year (Duke Energy Carolinas, LLC, 2014b).

The net metering policy also includes sizing rules for prospective net metering customers. The policy states that the net-metered system cannot exceed overall system demand. In my research, I interpreted this to mean overall annual kilowatt-hour demand rather than an estimate of the maximum kilowatt demand possible at any moment. In any case, a residential net-metered PV system in North Carolina cannot exceed 20 kW. I adhered to these rules for all of the configurations of PV systems that I used in my data analysis.

These dynamics provide for an unequal exchange of value in that it is possible for peak credits to offset off-peak usage, but not vice versa. Peak credits represent more retail value to DEC than off-peak credits, not just symbolically but monetarily: peak exports are sold to neighboring customers at peak prices, which accrue to DEC. When the credits from those exports offset off-peak energy usage, DEC keeps the difference between the peak rate and the off-peak rate. I have labelled this exchange as a credit transfer, and the values of each credit transfer are outlined in Table 3. It is important to note that the utility also benefits from the forfeiture of energy at the end of the utility year.

Table 3. *Values of Credit Transfers and Credit Forfeitures under DEC's RST Rate Schedule*

	Value Utility Receives	Value Customer Receives	Net Value to Utility
Peak winter to off-peak transfer	13.3437¢	7.0304¢	6.3133¢
Peak summer to off-peak transfer	14.7509¢	7.0304¢	7.7205¢
Peak winter Forfeiture	13.3437¢	0.0¢	13.3437¢
Peak summer Forfeiture	14.7509¢	0.0¢	14.7509¢
Off-Peak forfeiture	7.0304¢	0.0¢	7.0304¢

Note: All values shown are per kilowatt-hour of transfer or forfeit.

Table 4. *Sample Accounting Process for Exchange of Retail Value*

Step	Accounting Process	Peak Winter	Off-Peak
1	Customer usage (kWh)	258.8	769.7
2	PV generation (kWh)	365.2	605
3	Coincident use (kWh)	186.2	290
4	Imported energy (kWh)	-72.6	-479.7
5	Exported energy (kWh) and credits generated	179	315
7	Credits applied to in-class charges	72.6	315
6	Remaining charges balance	0	-164.7
8	Remaining credits balance	106.4	0
9	Peak to off-peak credit transfers	-106.4	106.4
10	Remaining charges balance	0	-58.3
11	Carryover credits from April 2010	74.9	0
12	Carryover credits applied in-class	0	0
13	Carryover peak to off-peak credit transfers	-58.3	58.3
14	Remaining charges balance	0	0
15	Remaining credits balance	16.5	0

Note: This is data from May 2010 for a customer with a south-facing PV array sized at a solar fraction of 75%, who uses gas heat. The order in which credits are applied to satisfy the off-peak charges balance reflects NC's net metering rules. The 16.5 kWh of peak winter credits remaining would be forfeited to DEC, since this is the last month of the utility year.

Once the amount and kind of credit transfers and credit forfeitures are known, which should come by the end of Step 3, Step 4 is simply multiplying the amount by the appropriate value from Table 3. This is how I quantified the exchange of retail value for net metering customers under DEC's RST rate schedule (Table 4).

Exchange of wholesale value.

While the exchange of retail value is determined by the rules of DEC's RST rate schedule and NC's net metering policy, and therefore must refer to the different price designations of electricity, the exchange of wholesale value measures all electricity, coming and going, against one value. That value is the wholesale cost of generation, which represents the variable costs of generating electricity.

The wholesale value of electricity for utilities is determined by a number of variables, including system-wide energy demand, fuel prices, and generator availability. These variables shift over time, such that the market-value of electricity changes from hour to hour, and from market to market. Locational Marginal Prices (LMPs) are a representation of the lowest price a market is willing to pay for the next available Megawatt-hour, and are a useful representation of the wholesale value of energy at any given time.

Net metering customers contribute to the wholesale electricity market by providing energy to the grid without receiving payment for it at that time. The wholesale value of the net metering exchange can be represented by the LMP of the energy that was exported to the grid, and the LMP of the associated energy that was offset by the customer and not paid for. To put it another way, net metering customers provide energy to the grid that the utility does not have to pay to generate, but then consume utility-generated energy without paying for it. This exchange means that there is a cost that the utility avoids when energy is exported, and a cost the utility does not recover when energy is offset. The difference between the two costs represents the wholesale value of the net metering energy exchange between customer and utility.

To determine the wholesale value of PV energy exported to the grid, I had to know not only how much energy was exported, but also what the LMP of each export was. To calculate the wholesale value of PV energy exports for a month, I multiplied each export by its associated LMP, and added all of the products together for the month. However, calculating the wholesale value of energy that a customer did not pay for on their monthly bill was more complicated.

Although it is simple to know when a customer imports energy from the grid, it is impossible to know what imported energy a net metering customer will or will not pay for. That is because a utility customer pays for his or her energy consumption in bulk, rather than piece by piece, and the wholesale generation costs of those pieces get averaged into the overall retail rate. Therefore, I could not use my methods to exactly calculate the wholesale generation costs that a net metering customer does not pay for.

However, I could use the same method I used to arrive at the wholesale value of exports to calculate the wholesale value of imports, and then divide that value by the total number of imports. Doing so yielded the weighted average cost of imports, which I calculated each month, and for each rate class for added granularity. I used this weighted average cost as a surrogate for an LMP for the offsets, and calculated the value of offsets by multiplying the amount of offsets by the weighted average cost of imports. Table 5 shows a sample of the data where there are both exports and imports.

Table 5. *Sample Data Showing Energy Flows and LMPs*

Timestamp	PV Energy	Customer Energy Use	Net Energy Flow	LMP ($/kWh)	Utility Cost of Energy Flow
6/4/05 6:00	0.00	1.47	-1.47	$0.0014	$0.00
6/4/05 7:00	0.33	1.46	-1.13	$0.0179	-$0.02
6/4/05 8:00	2.13	1.52	0.60	$0.0365	$0.02
6/4/05 9:00	2.77	1.59	1.18	$0.0343	$0.04
6/4/05 10:00	3.44	1.73	1.72	$0.0482	$0.08
6/4/05 11:00	4.74	1.85	2.89	$0.0512	$0.15
6/4/05 12:00	5.54	2.00	3.53	$0.0483	$0.17
6/4/05 13:00	4.87	2.16	2.71	$0.0362	$0.10

Note: All energy columns refer to kilowatt-hour values.

In this case, the sum of the negative utility costs would be divided by the sum of the negative energy flows to yield the weighted average cost of imports for this period. In this case, the weighted average cost of imports is $0.008/kWh. This is the cost that would be multiplied by the amount of offsets in the period to estimate the generation costs that the net metering customer did not pay for. Offsets are equal to exports, so in Table 5 there were 12.63 kWh of exports (Net Energy Flow), and if we assume that all of those exports became offsets, that would be an unpaid cost of $0.101 to the utility. This value stands to balance against the $0.56 of generation costs that were provided by the exports. By subtracting one from the other, one comes to see that the exchange of wholesale value in these eight hours provided a benefit of $0.459 to DEC. One would divide that value by the number of exports to arrive at the cost per export of net metering for these eight hours, which would be a benefit to DEC of $0.036/kWh.

As long as the amount of exports and offsets are the same in a month, the value of the exchange of wholesale value between customer and utility should be equal to the difference between the average value of exported energy and the weighted average value of imported energy multiplied by the total amount of exported energy in a month. If there are more exports than offsets in that month, then the benefit will be greater. This is particularly true for those exports that never offset any usage, but rather are forfeited at the end of the year. DEC benefits by the wholesale costs represented by those exports.

It should be noted here that the method I used to calculate the wholesale value of the offset energy is not precisely how a utility handles its wholesale energy costs. In general, a utility spreads the total amount of generation costs that have been incurred over a period of time into its different customer classes, such as those on residential, commercial, or industrial rate schedules. The proportion of costs that are borne by each class is determined by the proportion the class contributed to the peak system demand in the previous year. That is to say, if the utility experienced a peak electricity demand of 40 Gigawatts in 2007, and 10 Gigawatts of that came from customers on a residential rate schedule, then the utility would aim to recover 25% of its generation costs from residential customers. To follow this methodology one would have to expand the dataset to include overall system demand that was classified by retail rate class. While more valid, this approach is considerably more complicated, and is designed to arrive at a single dollar per kilowatt-hour energy charge that is applied to all hours of the year. My approach allowed the weighted average cost of wholesale energy to fluctuate month to month to yield a more accurate estimate of the value flows a utility experiences on a monthly basis.

To summarize, the wholesale value of an export is calculated every hour and summed up for a month, or a year, while the retail value requires a monthly reckoning of energy flows before value can be ascribed. However, once the values are arrived at, they are simply added together to yield a net total for the exchange of value between a net metering customer and

DEC. I applied this method for a study period of five years, from June 1, 2005 through May 31, 2010.

Methodology, Part 2: Experimental Design and Data Set Creation

The above section describes the model and method I used in my experimental investigation. As stated before, this model can be adapted to accommodate any time-synchronous suite of the four data sets I used (Customer Energy Use, PV Generation, Utility Wholesale Cost, Utility Retail Rate). Here I delve into how I used that model in my experiment, and how I created the data sets needed to run the model.

I tested two modeled customer energy usage profiles that were weatherized to actual measured weather data through six different PV orientations, at four sizes for each orientation. The energy usage profiles reflect a customer who uses gas heat, and a customer who uses electric heat. Both usage profiles model a cooling system that is responsive to weather trends.

I used measured weather data to drive a PV output model to create six PV orientations. The six different PV orientations include arrays oriented at 150°; 170°;180°, which is due south; 190°, which is west of south; 210°; and one array that is oriented at 180° but simulates one hour of energy storage (i.e., a battery designed to delay PV output by one hour). All PV orientations were designed to have a tilt of 36°, optimized for this latitude.

Each PV orientation was tested in proportion to the customer usage profile; that is, each orientation was tuned to generate 25%, 50%, 75%, and 100% of the customer's overall energy consumption, following the method used by Darghouth et al. (2010). This was repeated for both customer usage profiles, for a total of forty-eight trials (Figure 5).

I recorded many results for each trial, but the net value per kilowatt-hour of exported PV energy was the principal result for each trial in this research. In addition to net value and the variables of array size, orientation, and usage profile, I recorded the total amount of customer usage, coincident use, and PV generation, and the same values for summer, winter, and shoulder seasons. I defined summer as the months of June through September, winter as December through March, and the remaining months as the shoulder season. Finally, I itemized the bulk net value of each trial to capture what proportion of value came from retail exchanges, wholesale exchanges, or credit forfeitures. Figure 5 shows a flow chart of the trial iterations.

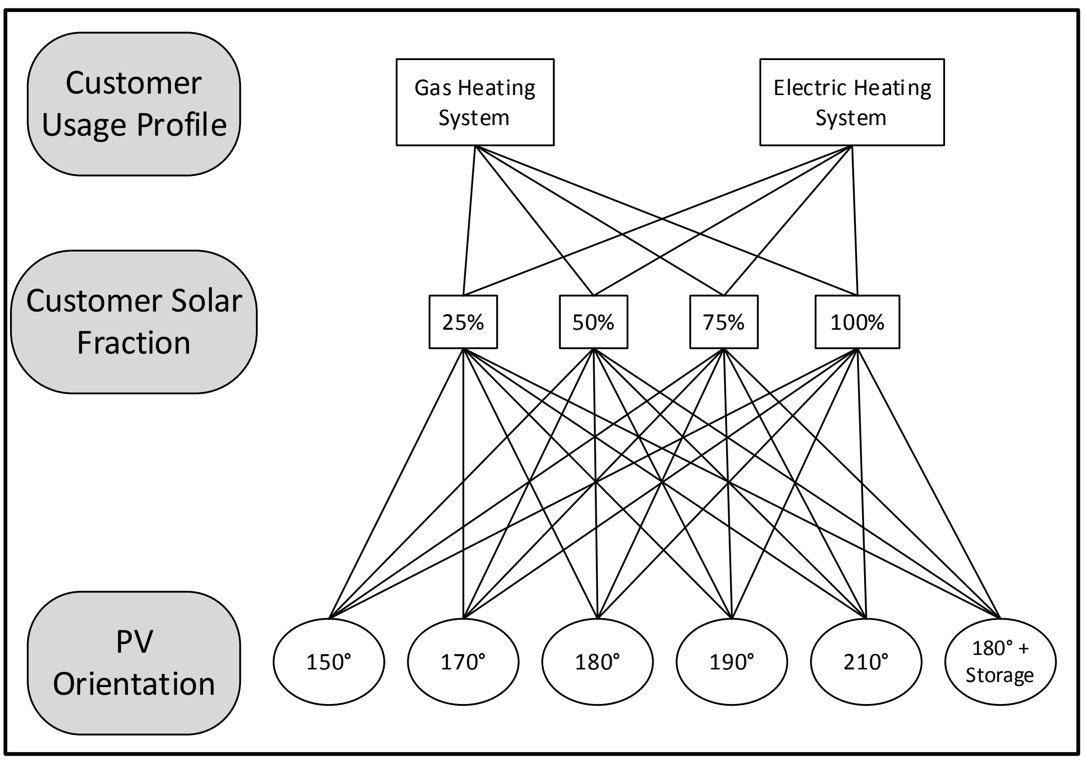


Figure 5. Flowchart of experimental iterations. Each box on the left is a variable that was tested throughout the model. Two heating systems were tested at four solar fractions in six different PV orientations for a total of forty-eight trials.

Data Sources

The above methodology describes how I used four separate data sets to create a model of energy and value flows over five utility years. However, acquiring the data was a major challenge for this research. To recap, the model was constructed using hourly data about a customer's energy usage, his PV energy generation, the wholesale costs of generation, and the retail price of that energy, and all of these data streams were intended to reflect normal conditions for a customer in Charlotte, NC. However, I was unable to fulfill any of these data sets directly with measured data for a net metering customer in NC, so all of these data sets were provided by surrogates. The energy data came from models which were weatherized using measured weather conditions in Charlotte, NC from June 1st, 2005 through May 31st, 2010. The value data came from DEC's RST rate schedule, and from a neighboring utility's published wholesale cost data. Each of these data sets, and any weatherization that was done to produce them, are described below.

PV power generation.

Solar photovoltaic panels have been thoroughly studied by Sandia National Laboratory, and there are several highly accurate models out there that can predict the performance of a PV panel if given environmental and panel data. My research used the equations that run the *PVWatts* online PV model, and use irradiance and weather data to produce accurate PV generation values for the study period.

PVWatts is a PV model developed by NREL using equations from Sandia National Laboratory (Dobos, 2013), and has been used before to model PV output in regards to economic trends (Darghouth, Barbose, & Wiser, 2014). The model parameters that were used in my research are presented in Table 6. Direct Normal Irradiance and Global

Horizontal Irradiance data were acquired from the National Solar Radiation Database (National Climatic Data Center, 2014). Temperature and wind speed data were acquired via the Quality Controlled Local Climatological Data database (National Climatic Data Center, 2015). Finally, the incident angle modifier was calculated using algorithms developed by NREL (Reda & Andreas, 2008).

Table 6. *Parameters for Solar PV Generation Model*

Albedo	0.2
Array IAM b_0	0.07
Module Temperature Coefficient a	-3.47
Module Temperature Coefficient b	-0.0594
Module Parameter E_0	1000
Module Parameter T_0	25
Module Parameter Gamma	-.50%
Balance of System Efficiency	90%

The product of the model and the data was a capacity factor for a PV array of a specified azimuth orientation and tilt angle. Capacity factor is the amount of a generating unit's nameplate capacity that is available at a certain time, from 0 to 1. By producing capacity factors for several different PV array orientations I was able to test various scenarios. Total PV array output is equal to the nameplate capacity of the array multiplied by the capacity factor.

Customer electricity usage.

Customer electricity usage data is essential to this research because it dictates how much PV generation is used on site and how much is exported onto the grid. Unfortunately, using customer usage data in a model is much more difficult than using PV generation data, for several reasons. Customer energy consumption is protected under privacy laws, so it is difficult to acquire in the first place. Also, this research is focused on a single net metering customer's interaction with a utility, which leads to a question of what customer usage profile should be used? Individual houses and households differ greatly from one another, and selecting one to be representative of net metering customers could create a bias. Furthermore, individual houses differ in age of construction, quality of construction, efficiency of appliances, and heating and cooling systems, all of which result in different energy usage per square footage; in addition, individual households have vastly different energy needs depending on household size and demographics, income level, and personal habits. There could be some value in aggregating the customer usage profiles of net metering customers across the system to arrive at a more representative dataset, but this approach would have all the same shortfalls as using a modeled customer usage profile without the robustness a well-designed model can provide.

In order to bypass questions of customer representativeness, and because of available data sources, I used a building model that was developed by NREL to set a benchmark for what a typical building built in 2010 would have consumed. This building model is referred to as the Building America B10 Benchmark (BA B10), and was developed by the Building America House Simulation for residential buildings (Hendron & Engebrecht, 2010). Building America is an NREL project that uses U.S. Department of Energy *EnergyPlus* simulation software to model hourly energy consumption in buildings. This model takes time-dependent effects such as thermal mass, passive solar heat gain, and outside wind speed into its calculations, as well as location-dependent variables such as the type of heating or cooling systems typical to a region. The building itself and the technologies used in it were designed to meet the International Energy Conservation Code of 2009, and is NREL's point of reference for tracking energy-savings goals (Hendron & Engebrecht, 2010). This model has also been used in several previous studies involving renewable energy and time-dependent datasets (Ong, Clark, Denholm, & Margolis, 2013; Ong, Campbell, & Clark, 2012).

Weatherizing load to ambient air temperature.

The BA B10 uses TMY2 and TMY3 weather data to create typical customer energy profiles for buildings across the nation. These weather data are NREL products that calculate a Typical Meteorological Year (TMY) for an individual location, based on 30 years of hourly weather data collected at each site by embedded weather stations. TMY data are less applicable in scenarios that examine how much energy a building *has* consumed in an actual year because they rely on long-term averages. I have weatherized the BA B10 model so that it showed sensitivity to the measured ambient air temperature used in the data that drove the solar PV model (National Renewable Energy Laboratory, 2015). There were considerable differences between the benchmark model and the weatherized data set (Figures 6 and 7).

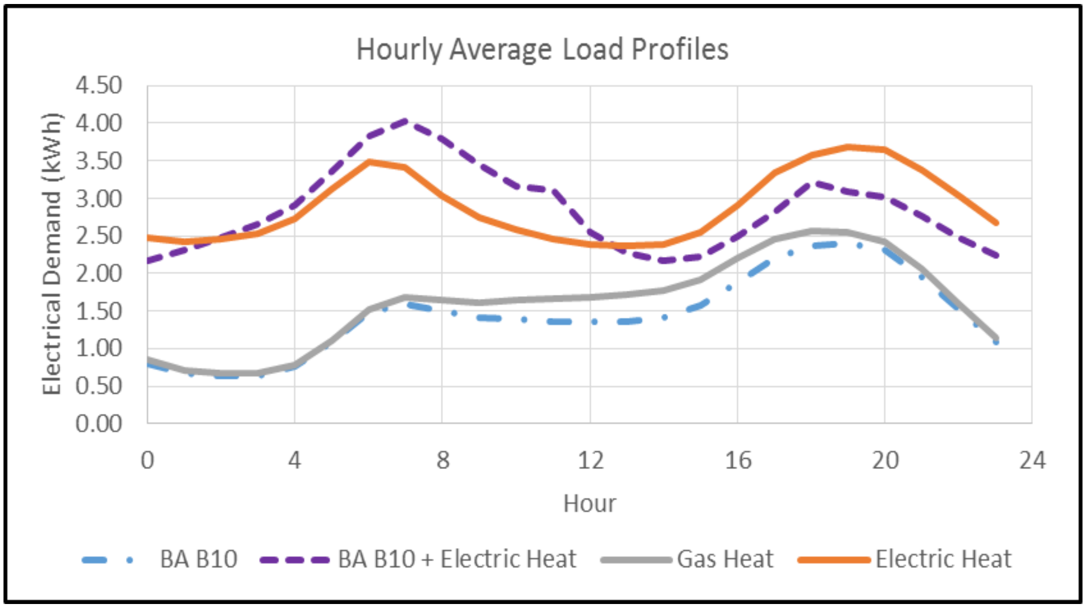


Figure 6. Plot of hourly average energy usage for benchmark and weatherized customer. This hourly plot of the average electricity demands shows the differences between the benchmark model and the weatherized dataset. The weatherized data shows a greater cooling demand for gas heat customers, and a lower heating demand in the morning for electric heat customers.

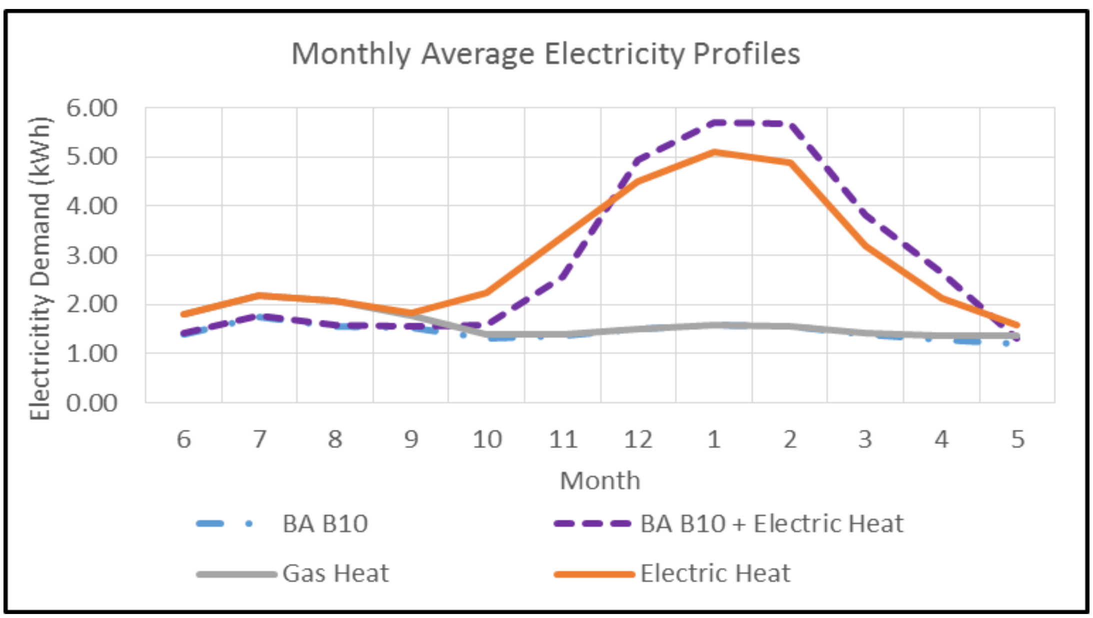


Figure 7. Plot of monthly average energy usage for benchmark and weatherized customer. Shows the differences between the benchmark model and the weatherized dataset – there is a greater cooling load for weatherized dataset, and a greater electric heating load for the benchmark. The dotted lines represent the benchmark model for the two heating scenarios, and the solid lines represent the weatherized results for the two heating scenarios.

The differences between the TMY2-driven model and the 2005-2010 data-driven model are broadly predictable by weather trends of the years 2005 through 2010. Four out of the five years of the study period were in the top ten warmest years on record as of 2014, which could explain why the weather-driven cooling load is greater than the TMY2 model, and why the weather-driven heating load is lower than the TMY2 model (NOAA National Climatic Data Center, 2014). This is an indication that the weatherization method I describe below performed reasonably well.

The benchmark BA B10 model contained subsections describing different electrical loads for each hourly record. Two of these subsections pertained to a heating load and a cooling load. A regression analysis of the dataset showed a strong correlation between temperature and the heating and cooling loads (Figures 8 and 9).

The benchmark model contained its own rules dictating heating and cooling loads. Unfortunately, I did not find the equations that governed those rules, and was forced to reverse-engineer the heating and cooling logic. I did this by isolating the heating and cooling loads, and identifying what ambient air temperature values had heating or cooling usage in that hour. This indicated what setpoint temperature the benchmark model used to start its heating or cooling load. Using this setpoint, I graphed the temperature of those hours against the heating or cooling load. I then performed a linear regression on the data and calculated the R^2 value of that line. The graphs are displayed in Figures 8 and 9.

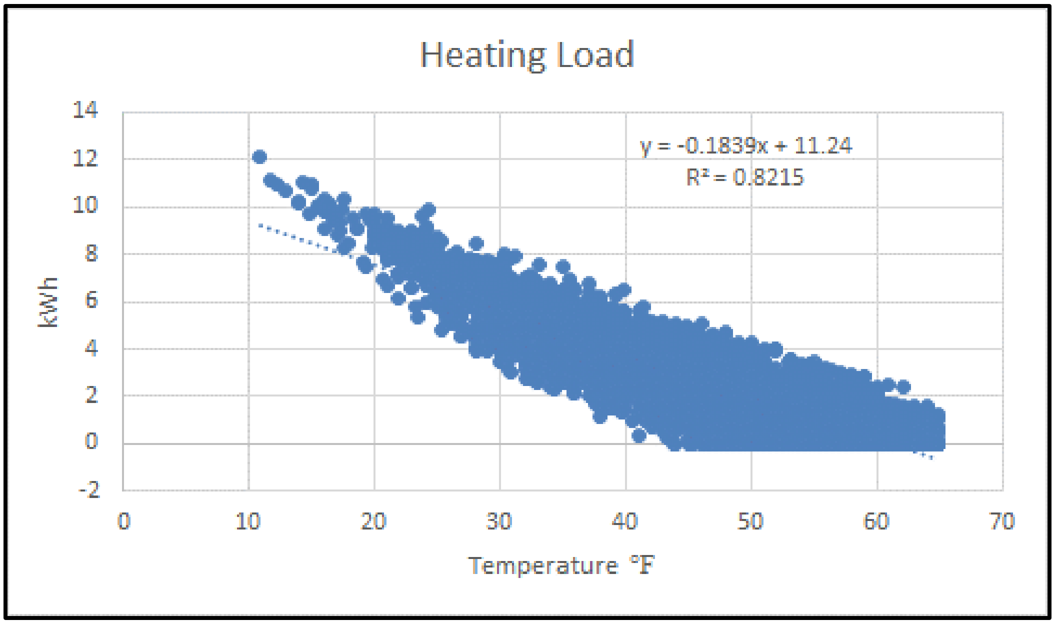


Figure 8. Plot of TMY2 temperatures related to heating load in benchmark model. The results indicate a correlation between falling temperatures and increasing heating load.

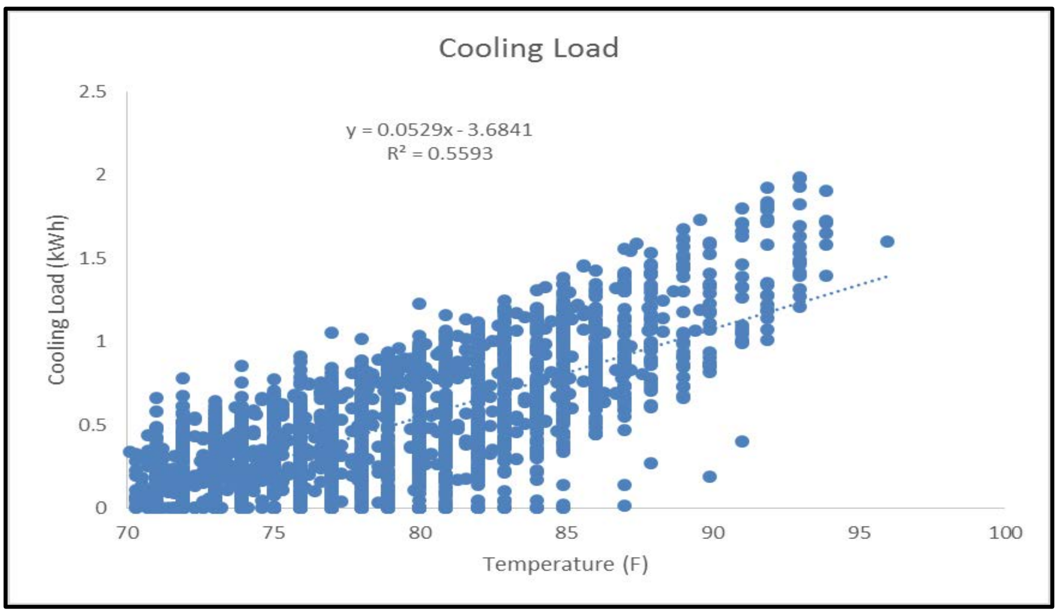


Figure 9. Plot of TMY2 temperatures related to cooling load in benchmark model. The results indicate a positive correlation between ambient temperature and cooling load.

Table 6. *Heating and Cooling Parameters for Customer Usage Model*

	R^2 Value	Slope	Y-intercept
Heating Demand	0.8215	-0.1839	61.12
Cooling Demand	0.5593	0.0529	69.64

Note: The y-intercepts are equal to the setpoints I used to simulate heating and cooling loads. Heating load was active at temperatures below 61.12° F, and cooling load was active at temperatures above 69.94° F. The setpoints for the benchmark BA B10 model were different.

The goal of the regression analysis was to estimate heating and cooling loads as a function of ambient air temperature. Figures 8 and 9 and Table 6 show that while ambient temperature does not perfectly explain the BA B10 heating and cooling demand, there is a distinct trend. The regression showed an R^2 value of .82 between heating demand and ambient air temperature, and an R^2 of .55 between cooling demand and ambient air temperature. The imprecision of the regression in predicting the cooling demand, for example, should not throw out the regression as a functional way of adjusting the model for weather data, because Figure 9 also shows a great deal of variability in the cooling load. The fact that the regression bisects that variability indicates that it is suitable in predicting the broad correlation between temperature and cooling load, which is all that is required for this analysis. The broad trends allow the heating and cooling demands to respond to weather events, and thus allow the modeled building data to perform reasonably in conjunction with the measured PV generation data.

The final part of the process of weatherizing the BA B10 model to real-time weather data was acquiring the weather data. I acquired data that was gathered at the Charlotte Douglas International Airport from the North Carolina State Climate Office (SCO), for the time period from June 1, 2005 through May 31, 2010. The SCO provides many different hourly weather variables for download, but this normalization required only ambient air temperature. The dataset was also remarkably complete as only 1% of the 43,872 records were missing, blank, or failed the SCO quality control test. I filled in these missing values using a linear equation derived from the last measured value and the next measured value, a technique that NREL published in their guide to using real-time weather data (Long, 2006).

This was not the source for the temperature and wind speed data used to model PV generation. These data were unavailable when I was modeling customer energy usage. However, both data sets were measured at the Charlotte-Douglas International Airport, presumably using the same measuring apparatus, so there should be ample agreement between the two.

Once I had a suitable temperature dataset for the study period, I used the heating and cooling setpoints and the linear regression equation to produce heating and cooling demands based on ambient temperature. On average, the cooling demand of the weatherized data set was 11% greater than the benchmark model without weatherization, while the heating demand was 4.5% less than the benchmark model without weatherization. The average hourly electricity demand profiles are presented in Figure 6.

Utility wholesale generation costs.

I used the Locational Marginal Prices (LMP) for the Dominion Hub of the PJM Interconnection, which is the wholesale market value of energy for PJM, to represent the wholesale generation costs for our model. This method has been described by Denholm et al. as being the most accurate method for what the generation costs of a system *were* at a specific time in history (Denholm, Margolis, Palmintier, Barrows, Ibanez, & Bird, 2014). That is because the LMP is a reflection of how valuable the next available unit of energy would be on the market, and accurately reflects the generation mix and the price of fuel that was being used to satisfy grid electricity demand.

The LMP data for Dominion was acquired by using the PJM Data Miner application at https://dataminer.pjm.com/dataminerui/pages/public/lmp.jsf. I used the Total LMP for the Dominion Hub, and sorted the resulting datafiles into hourly datasets from June 1, 2005 through May 31, 2010. The data displayed significant variation over the hourly average wholesale value (Figure 10), and there was significant variation in the value of electricity from year to year (Figure 11).

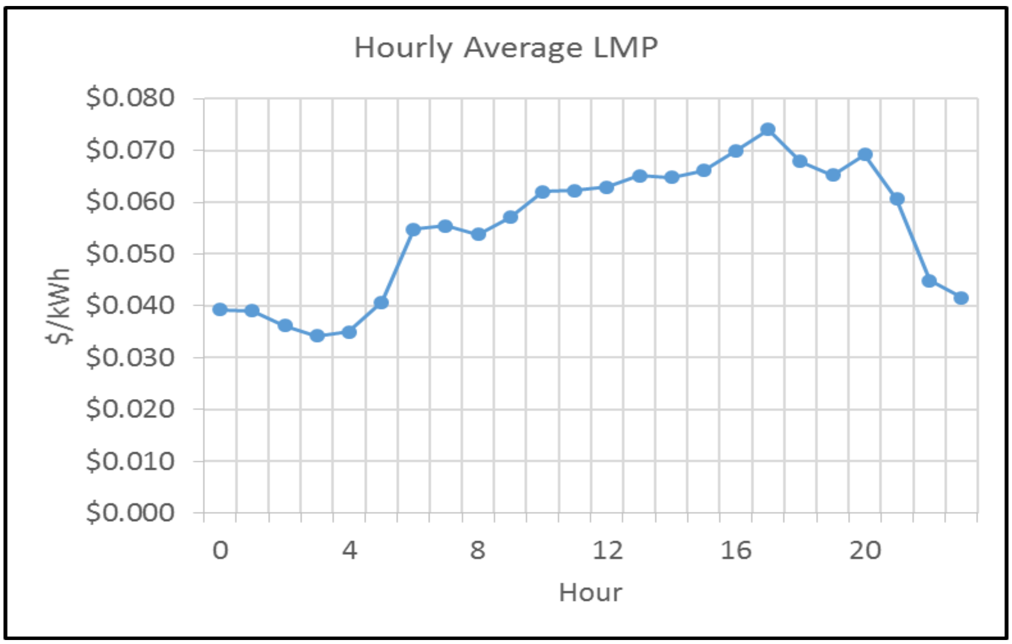


Figure 10. Hourly average of LMP data. The hourly average price of generating electricity had considerable variability in my study period. The overall average was $0.059/kWh.

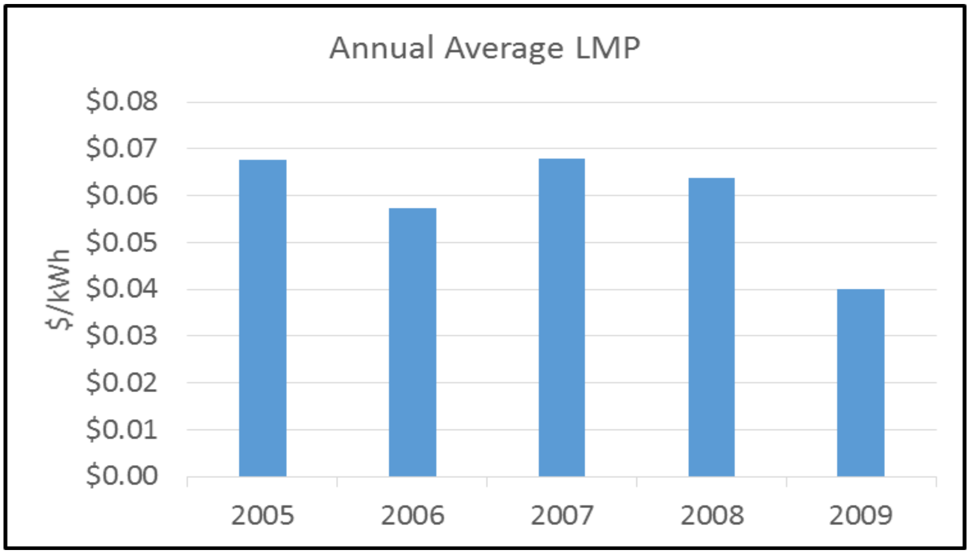


Figure 11. LMP trends during study period. The average price of a kilowatt-hour changed from year to year. The overall average for the five-year study period was $0.059/kWh, which is almost two full cents higher than the 2009 average LMP.

CHAPTER 4: RESULTS AND DISCUSSION

My research set out to evaluate whether net metering inherently provides a benefit or incurs a cost upon Duke Energy Carolinas. I have evaluated the claim by focusing on the exchange of energy and value between a theoretical net metering customer and DEC, and by quantifying that exchange's cost or benefit in a variety of scenarios. I have found that DEC benefits from almost every net metering scenario I have tested, and the remaining scenarios impose a miniscule cost per customer.

The overall results fall into general trends with little variability, but these hide the teeming diversity of factors that go into each result. Each net value for each scenario has two major sources of benefit, and these sources can be subdivided into finer and finer granularity for a fuller understanding of the dynamics of the exchange of value in a net metering scenario. Like a teaspoon of dirt whose apparent homogeneity belies an underlying diversity of components down to the component level, net metering is more than a black or white issue. In the results created from this data set, there are nearly endless perspectives one can take on the matter. In fact, there were over 40,000 hourly data records in this study, and these varied in each of the forty-eight unique iterations analyzed. Of these almost 2,000,000 possible interactions, there are bound to be countless trends and differences; however, only some can be called compelling, and only some can be considered relevant to this argument.

Sources of Value

Retail Value

The two major sources of benefit for a net metering system are the exchange of retail values and the exchange of wholesale values. The exchange of retail value is a byproduct of the TOU-energy rate that DEC offers, which differentiates the retail price of electricity by hour of day. The TOU rate designates hours as being either peak or off-peak, and designates months as being summer months or winter months, and the rate of electricity is dependent on these designations. Customer usage interacts with peak retail rates in varying ways over a day and over the year, according to the heating system that they use (Figures 12 and 13).

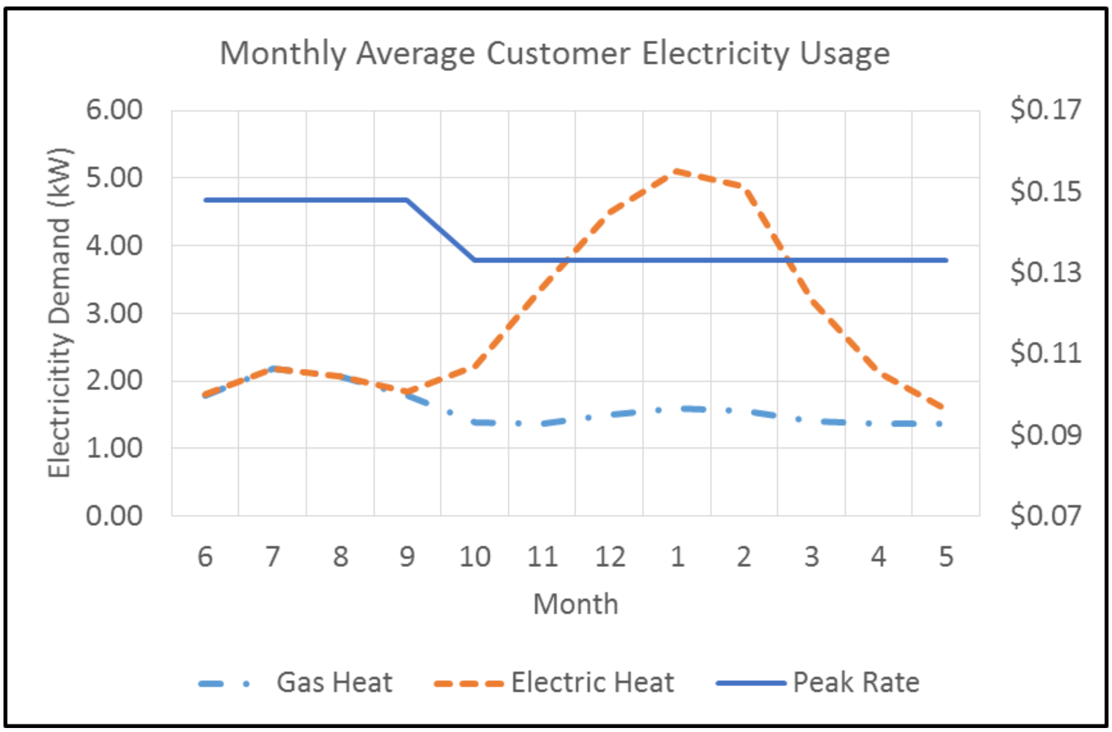


Figure 12. Plot of monthly average customer energy use and peak retail rates. Both customer electricity usage and peak retail rates change throughout the year, which is presented here in order from June – May, corresponds to DEC's billing year. A customer with gas heat uses electricity more in the summer than any other time, while a customer with electric heat uses much more electricity in the winter than the rest of the year.

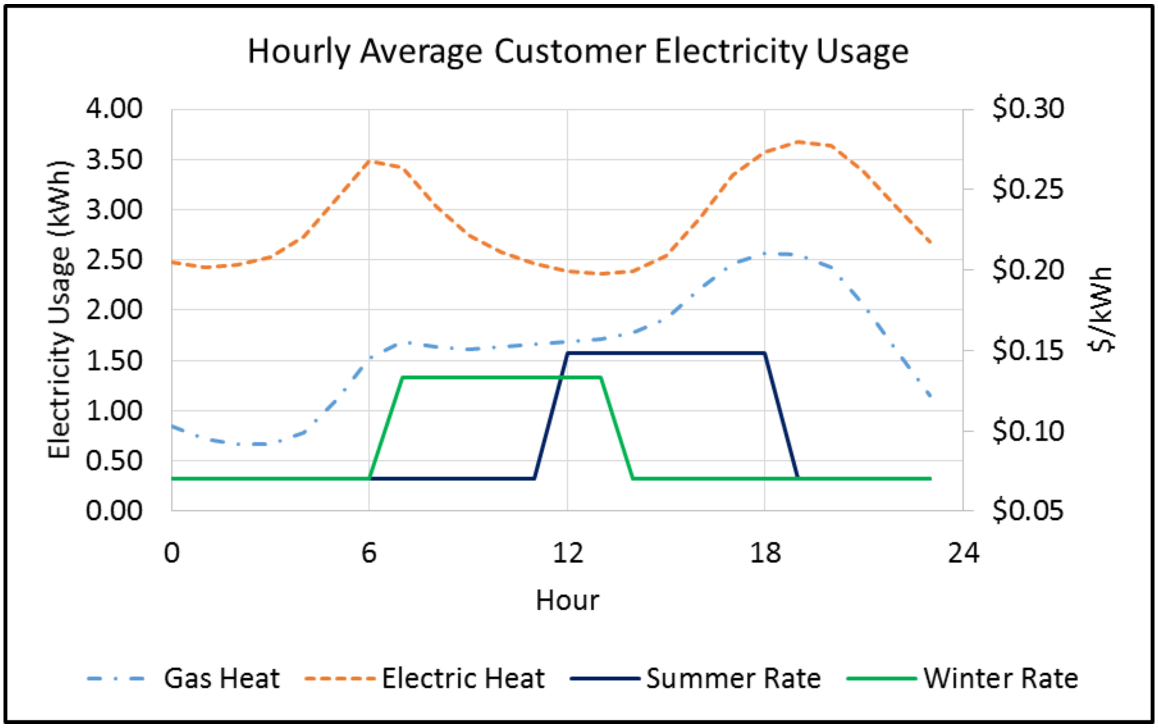


Figure 13. Plot of monthly average customer energy use and peak retail rates. The dashed lines represent the prevailing retail rates under DEC's RST rate schedule. The solid lines represent hourly average customer electricity usage from my data. The customer with electric heat uses almost twice as much total electricity, and much more electricity in the morning, than the customer with gas heat. The off-peak rate is the same in both summer and winter.

Figures 12 and 13 provide a picture of the physical and temporal characteristics of a net-metered PV system. These characteristics define the results of the exchange of retail value between a net metering customer and DEC. The first effect related to the TOU rate schedule is that an unequal exchange of retail value can occur. If a customer exports a lot of peak energy, and some of it is used to offset off-peak energy usage, then that transferred portion represents an unequal exchange of retail value. DEC benefits in these credit transfers by the difference between the retail rate and off-peak rate.

Figures 12 and 13 also indicate the scale of the energy flows in this study. Over the five years of modeled electricity use, the customer using gas heat used 70,652 kWh of electricity, or approximately 39 kWh per day. The customer using electric heat used 126,825 kWh of electricity for a daily average of 69 kWh per day. For comparison, the USEIA calculated that the average residential utility customer in North Carolina used just over 13,000 kWh of electricity in 2013, which would extrapolate to 65,000 kWh over five years (USEIA, 2015). While my numbers are higher than this, they are not out of the ballpark.

For a credit transfer to occur, two things must happen. First, there must be excess peak PV energy, such that in peak hours a customer creates more energy with PV than he uses in his home, and secondly there must be off-peak imports. These two variables change based on the customer's heating system, PV orientation, and solar fraction of energy use.

Excess peak PV energy represents the potential for value because of the exchange rules of net metering. In North Carolina, a net metering customer under a TOU rate may use peak exports to offset peak imports, and the same for off-peak exports. The customer is also allowed to offset off-peak imports with peak exports, but not vice versa. Using peak exports to offset off-peak imports represents an exchange of value to DEC's benefit because all exported energy is sold at the prevailing retail rate, which provides a retail income stream to the utility and which balances the retail rates that are avoided through net metering. I have called this situation a credit transfer. Additionally, a customer is only allowed to have a net-metered PV system that is sized to provide 100% of his energy use, and that PV system cannot be larger than 20kW for a residential customer.

Figure 14 shows the dollar per kilowatt-hour contribution of retail credit transfers to the net value of a net metering system. Both heating systems are displayed, and the graph indicates that an increase in solar fraction does not necessarily mean an increase in credit transfers. This is due to the dual nature of credit transfers. As solar fraction increases, there are more excess peak exports available for transfer; however, there are also fewer available off-peak imports to offset, which limits the potential for credit transfers. Figures 15 and 16 show the trends of peak exports and off-peak imports.

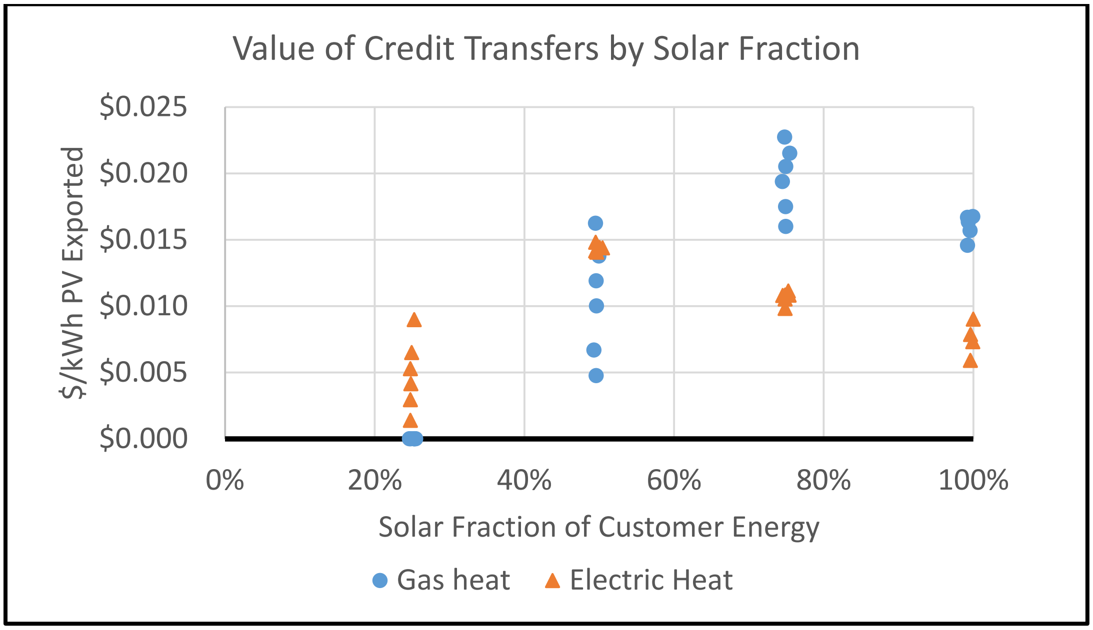
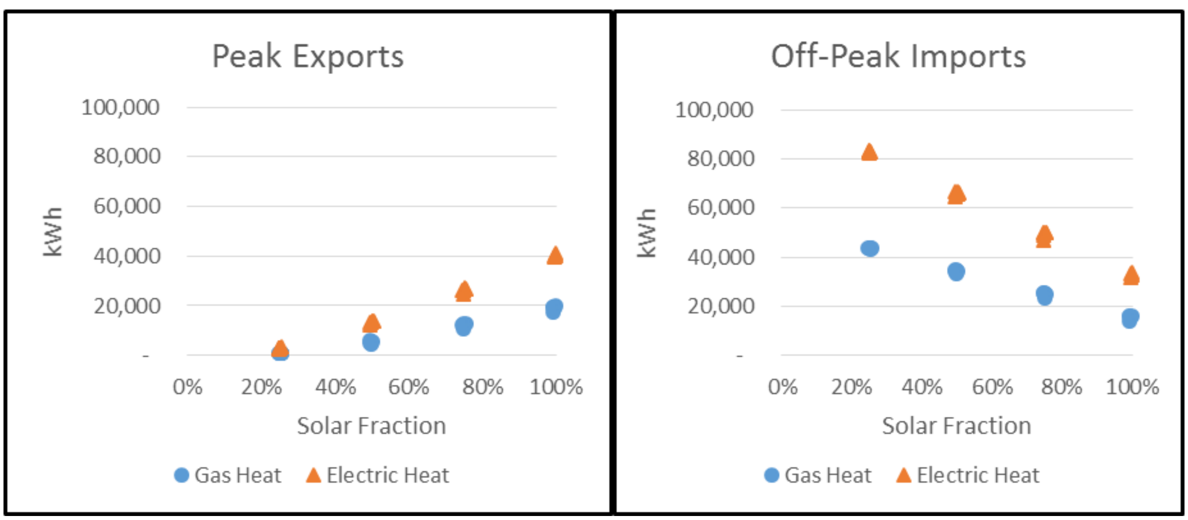


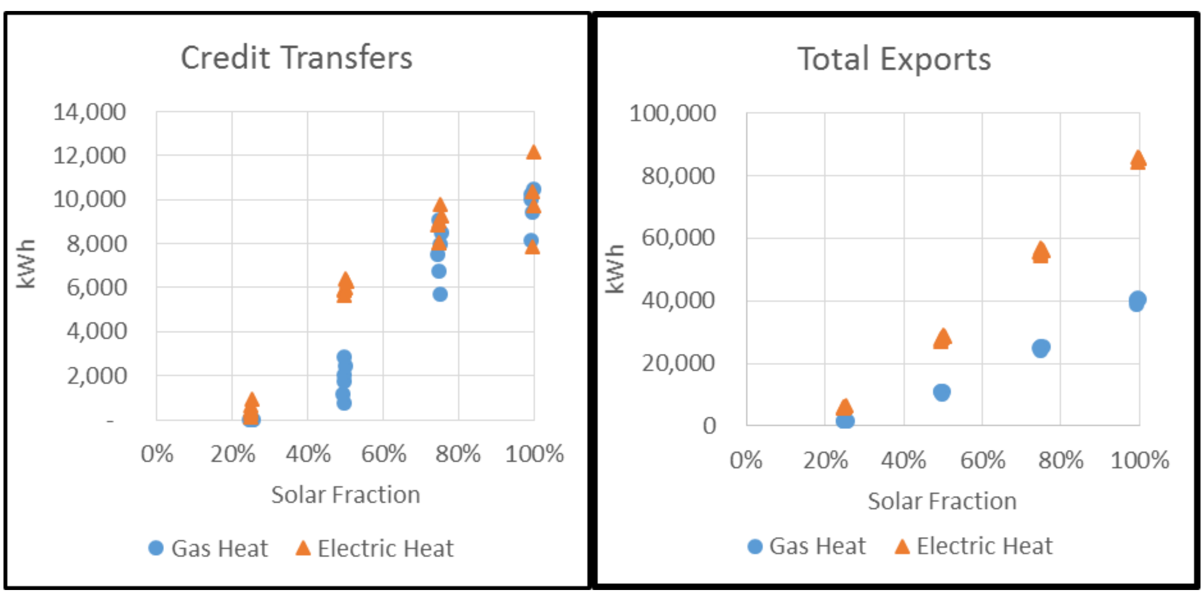
Figure 14. Value of credit transfers by solar fraction. The net value of credit transfers clearly peaks at smaller system sizes for both gas heat and electric heat. Value is expressed in terms of dollars of benefit per kilowatt-hour of PV exported onto the grid.



Figures 15 and 16. These two graphs show the gross amount of peak exports, and net off-peak imports. The number of peak exports does not take into account how much goes towards peak imports, and the number of off-peak imports is what can't be covered by off-peak exports.

The trends shown in Figures 15 and 16 do not fully explain Figure 14. The only scenarios in which peak exports exceed off-peak imports in Figures 15 and 16 are at solar fractions of 100%, while the value of credit transfers in Figure 14 peaks at a solar fraction of 50% for the electric heat scenario. This discrepancy indicates that there is more to the story of credit transfers here.

First of all, net value is calculated as the dollar of value per kilowatt-hour of PV energy that is exported by a system. As Figure 17 shows, credit transfers increase linearly with greater solar fractions, but with a much smaller slope than the total amount of exports (Figure 18). Thus, while larger systems provide more gross revenues to DEC, they do so with increasingly large amounts of exports. It is the value of total exports that is important because this is the body of electricity that makes use of the electrical grid.



Figures 17 and 18. Plot of credit transfers by solar fraction, and plot of total exports by solar fraction. Both credit transfers and total exports increase as a function of solar fraction. However, there are many more exports than credit transfers, diluting their effect. Significant variation appears in the graph of credit transfers.

Secondly, as a net-metered customer increases the solar fraction of his usage, excess energy is created at the end of the utility year that is eventually forfeited to DEC. Any PV credits remaining at the end of May each year are relinquished to the utility, and are unavailable for further offsets or credit transfers. This dynamic is particularly pronounced in North Carolina because spring is when customers use the least amount of energy, on average, and solar arrays perform well due to lengthening days and cool temperatures. Figure 19 displays this dynamic for a south-facing system with a 100% solar fraction. The only season during which surplus PV energy is generated are the shoulder seasons, which are the months of October-November and April-May.

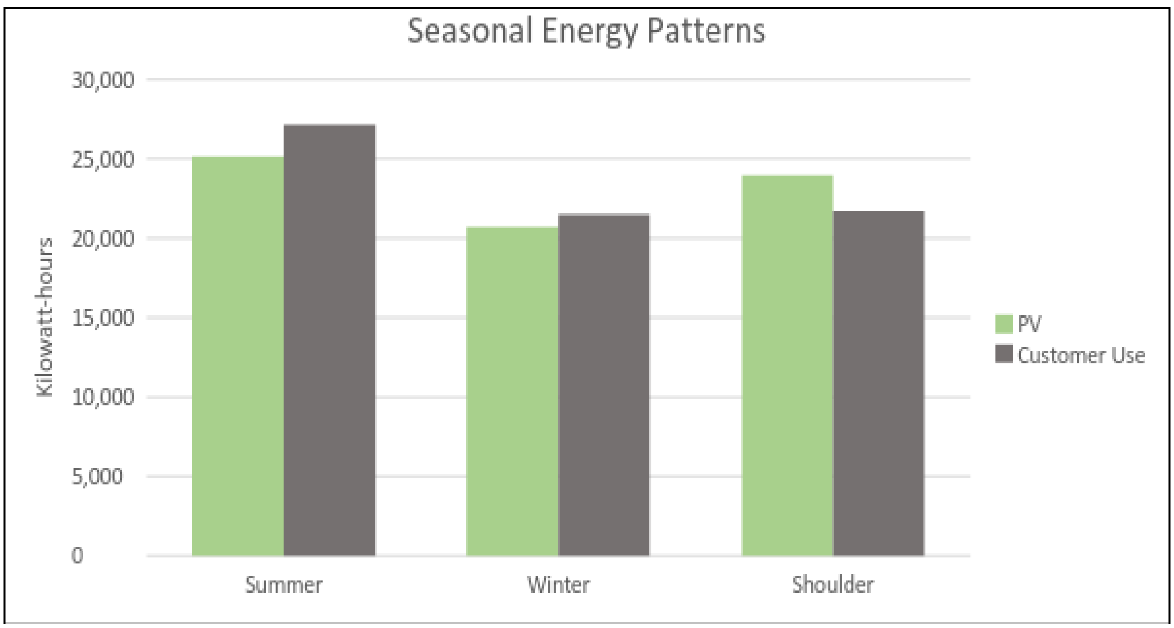
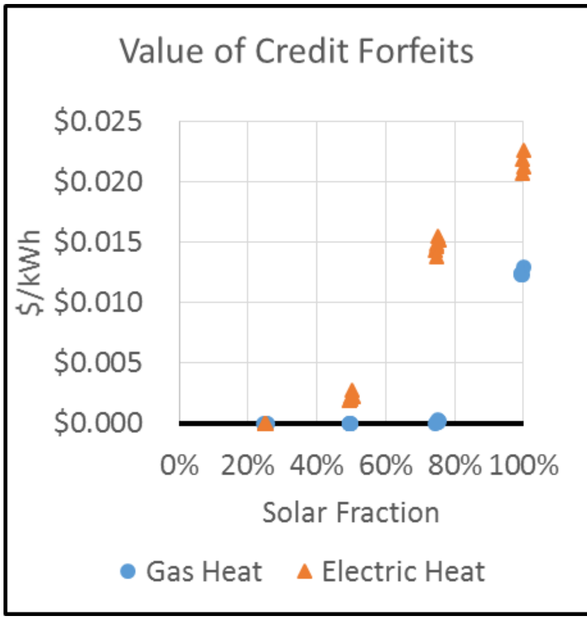
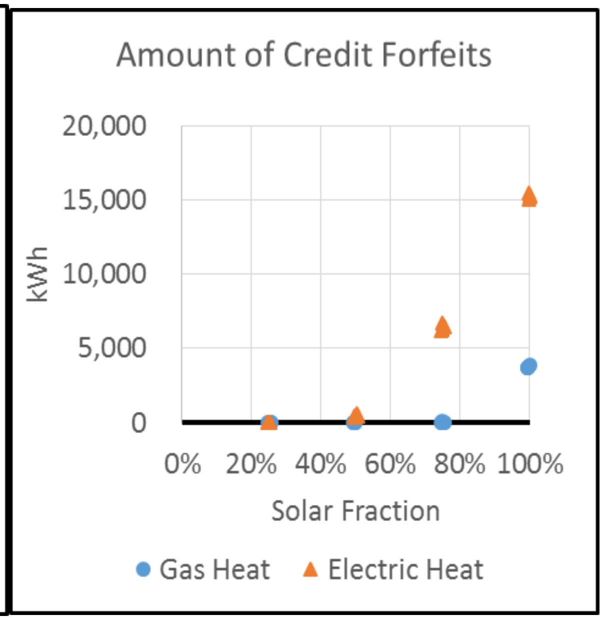


Figure 19. Seasonal energy patterns of customer with 100% solar fraction. Solar energy is exceeded by customer energy use in all seasons except for the shoulder season. This scenario is for a customer with a 180° PV system using gas heat. Shoulder season months are October, November, April, and May.

This trend becomes distinctly clear when looking at the amount of credits forfeited throughout the scenarios. Systems with solar fractions above 50% forfeit a great deal of credits (Figures 20 and 21). All of these credits were exports that were sold at the retail rate to some utility customer, and folded into DEC's revenues, while none of them were able to decrease that revenue by offsetting other energy imports. When credit forfeitures and credit transfers are combined, the total amount of benefit of the exchange of retail values appears to increase linearly with solar fraction, as shown in Figure 22.





Figures 20 and 21. Plot of value of credit forfeits by solar fraction, and plot of amount of credit forfeits by solar fraction. The amount and value of credit forfeitures is significant at solar fractions above 50%. The growth appears linear with electric heat systems.

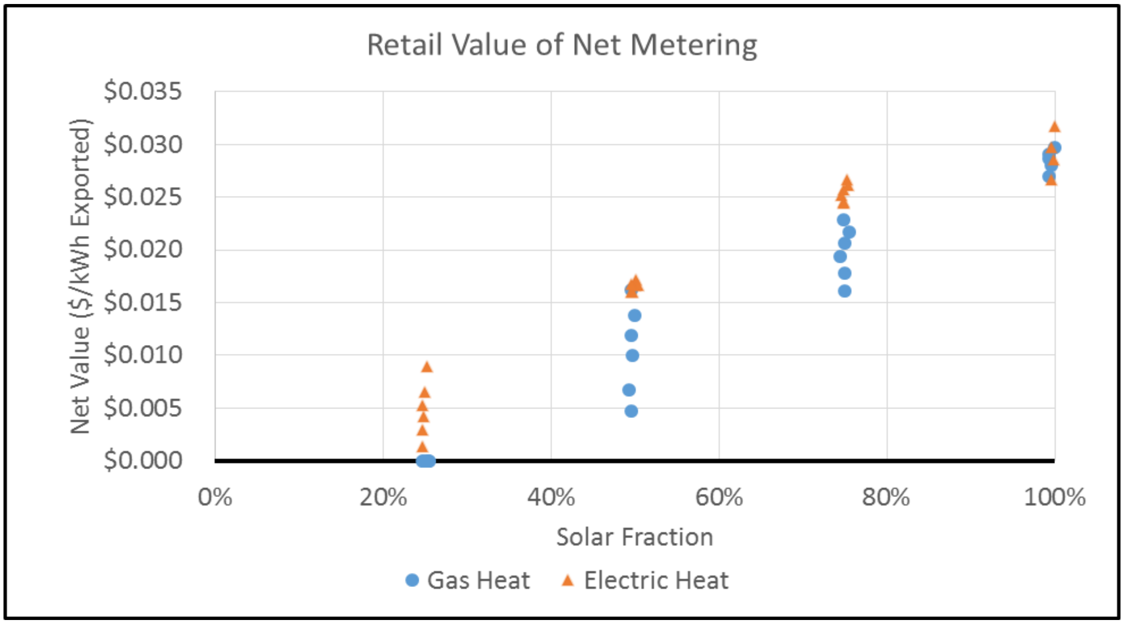
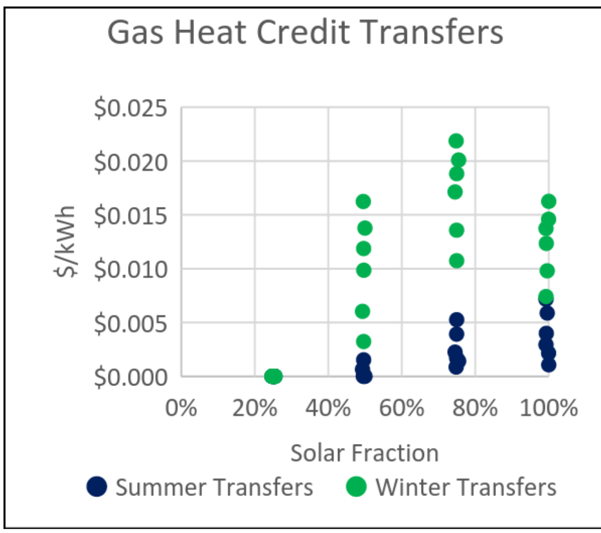


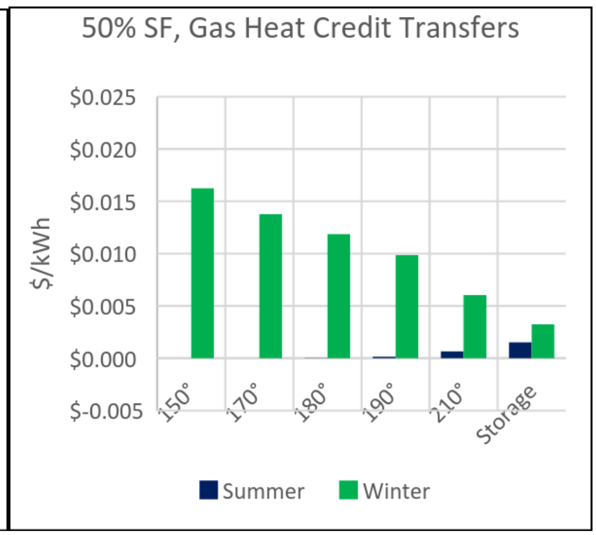
Figure 22. This is the full contribution of the exchange of retail values to the net benefit of a net metering system. This is expressed as dollars per kilowatt-hour exported, per year.

The major takeaway from the trends in the exchange of retail value is that all scenarios increase in value accrued to DEC per year according to their solar fraction. However, there is significant variation for all systems with a solar fraction less than 100%. This variation is due to both the heating system used, and the orientation of the PV system. As one can see in Figure 22, the retail value of net-metered PV systems with electric heat are consistently higher than those with gas heat, until they converge at a 100% solar fraction. The PV systems with gas heat also show significant variation at the same solar fractions, which suggests that PV orientation can have a significant effect on the retail value for gas heating customers.

The largest variation was for gas heating customers with a 50% solar fraction. In this variation, a system oriented to 150° azimuth had a retail value of $0.016/kWh exported, while a system that was oriented to 180° azimuth but used one hour of storage had a retail value of $0.005/kWh. The 150° scenario encouraged morning PV exports, while the storage scenario strongly encouraged afternoon PV exports.

This variation is somewhat unintuitive. The greatest retail value can be generated in summer afternoons, as seen in Figures 12 and 13, but the system produced the most retail value, at 50% solar fraction, when it produced the least amount of afternoon PV energy. The reason for this is that the net-metered systems that used gas heat could not generate enough PV energy during summer afternoons to satisfy the electrical demand for cooling. Thus, while these systems exported the same amount of energy as all the others (Figure 18), they did not have nearly as many credit transfers (Figure 21). In fact, when one investigates further, net-metered systems with a solar fraction of 50% for gas heating customers had very few transfers of summer peak credits (Figures 23 and 24).





Figures 23 and 24. Plot of credit transfers for all gas heat scenarios, and plot of credit transfers for gas heat scenario with 50% solar fraction. The trend for winter transfers in Figure 23 should be of note, because it peaks at a solar fraction of 75%. Summer credit transfers appear to increase linearly at solar fractions greater than 25%.

There is a physical explanation for the retail value results of net metering customers using gas heat. Quite simply, their annual electricity demand is defined by the cooling load they have in the summertime, which coincides with both the peak summer retail rates and afternoon PV production (Figures 12 and 13). It is this load that a gas heating customer is seeking to offset with a net metering system, and that it does so with little excess is validation that the system is doing its job. In fact, this indicates that net-metered PV really does satisfy afternoon summer electricity demand, which has been touted as the principal societal benefit of PV since the 1990s (Haas, 1995; Perez, Seals, & Stewart, 1994). This physical process is also evident for customers with electric heat—their electricity usage pattern is defined by heating needs, which are higher in non-daylight hours, so there is less opportunity for the PV energy to be consumed on site. Instead, that energy is exported and used to offset nighttime electricity use.

This process is built into the idea of net metering, which has always been that a customer could achieve an energy bill of zero dollars from the utility company. For a customer to do this under normal energy usage patterns, however, he would have to trade electricity with the utility, within the day and within the year. Customers will never produce PV energy at night, so if they want to "net out" their total energy usage, they'll have to produce excess energy during the day. This dynamic should align well with DEC's needs; they plan their generation capacity in order to meet daytime energy use, and doing so allows them to easily meet nighttime energy demand. A net metering customer who is incentivized to produce excess daytime energy should be seen as an asset and a resource to DEC and other utility customers, not a burden, and the results of the exchange of retail value support this general intuition. If the retail rates truly reflect the DEC service area's costs and needs, it is clear that net metering customers provide a service and a benefit to both DEC and to other utility customers.

Wholesale Value

Another test of the value of a net metering customer's excess energy is how well it aligns with the raw generation costs that a utility must account for when providing electricity. While the retail rates covered above are intended to reflect DEC's broad trends in electricity production needs, the wholesale generation costs provide an unadulterated look into how well net-metered PV aligns with a utility's and with other ratepayers' needs.

The window that one can look through to see the costs of electricity generation is the LMP, which is a calculation of how valuable the *next* unit of generated electricity would be. The LMP is place specific (hence, "locational"), and time specific. The LMPs that I have drawn from are hourly calculations, while some Independent Service Operators provide LMPs every fifteen minutes. Although the temporal relationship between electricity and TOU retail value is structured and mandated by DEC with its RST rate schedule, the temporal relationship between LMPs and electricity must be discovered through an analysis of the data. I have calculated the monthly and hourly averages of the LMPs in my data and these broad averages indicate that there are trends in the wholesale value of electricity during the day and over the course of a year.

The retail rates above indicated that daytime electricity was much more valuable than nighttime electricity, and that summer electricity was somewhat more valuable than winter electricity. These trends are also evident in the monthly and hourly averages of LMPs (Figures 25 and 26, respectively). This indicates that, on the wholesale level, a net metering customer who is exporting daytime PV energy to offset nighttime energy usage is providing a service to DEC and to other ratepayers. The same is true for a customer who exports a great deal of PV energy in the summer to offset high energy usage in the winter. However, what about the customer whose energy usage closely resembles the monthly and hourly trends in the LMPs, like the customer with gas heat shown in Figures 25 and 26?

As one might expect, the results show that these customers provide less of a service to other ratepayers than customers with electric heat (Figure 30). For this customer to have a zero dollar energy bill with net metering, he must offset the energy that he uses in the afternoon on summer months. This means that this customer satisfies his billing demands with less exports than a customer with electric heat (Figure 29), and he predominantly consumes high-value electricity. If his times of energy consumption and PV energy generation are the same, one would expect the exchange of wholesale value for this customer to be close to zero, because he and DEC are exchanging similar products. The results support this intuition, as seen in Figures 27 and 28: customers who use gas heat have very similar weighted average costs for their exports and for their offsets, and do not provide a large cost or benefit at any solar fraction.

Moreover, for this customer to have an annual solar fraction of 100%, he must be a net consumer of energy in the summer and a net exporter at other times of the year. Figure 8 shows exactly this dynamic happening for a customer with gas heat and a 100% solar fraction. This customer is a net consumer of energy during the summer and winter, when wholesale costs are above average, and a net exporter when wholesale costs are lowest. Simply put, his energy usage pattern is misaligned to provide much wholesale value to the utility or to other customers.

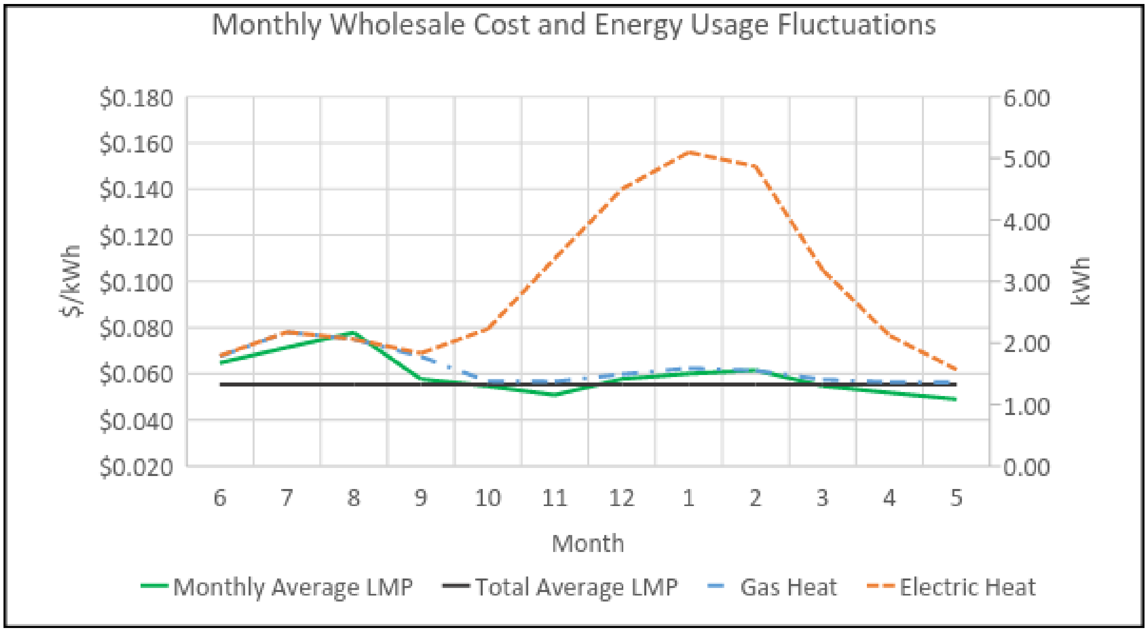


Figure 25. The monthly averages of LMP and customer energy usage. The year is arranged from June to May to match DEC's billing year. The total average LMP refers to the average LMP value over the whole study period. Note that the only months below this average are October, November, March, April, and May.

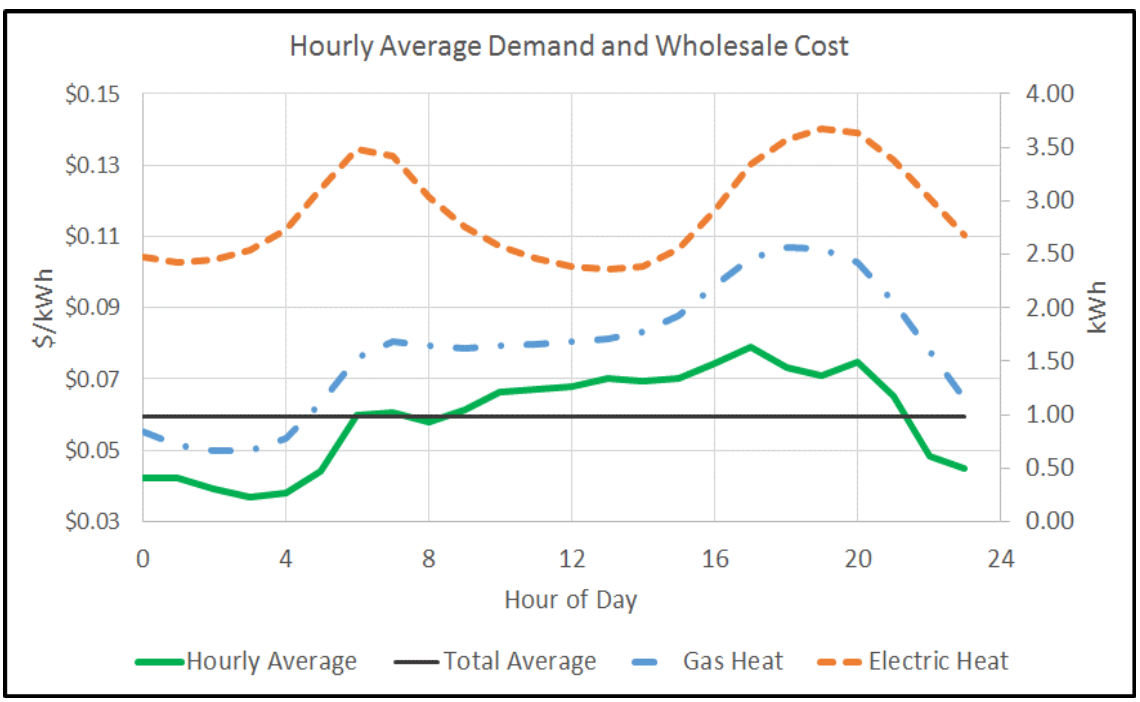
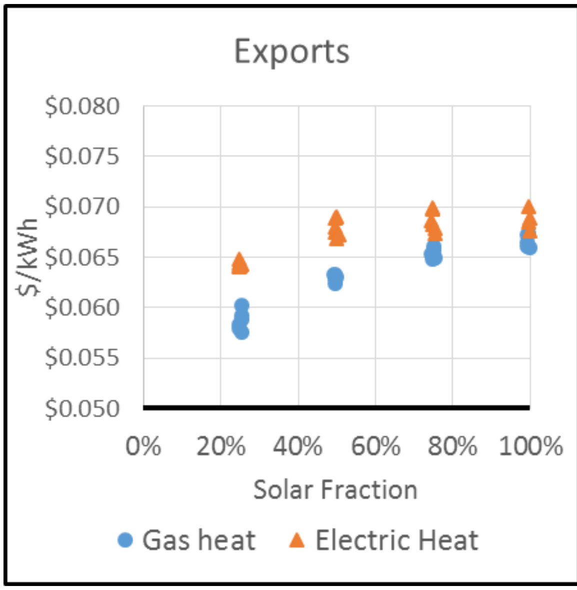
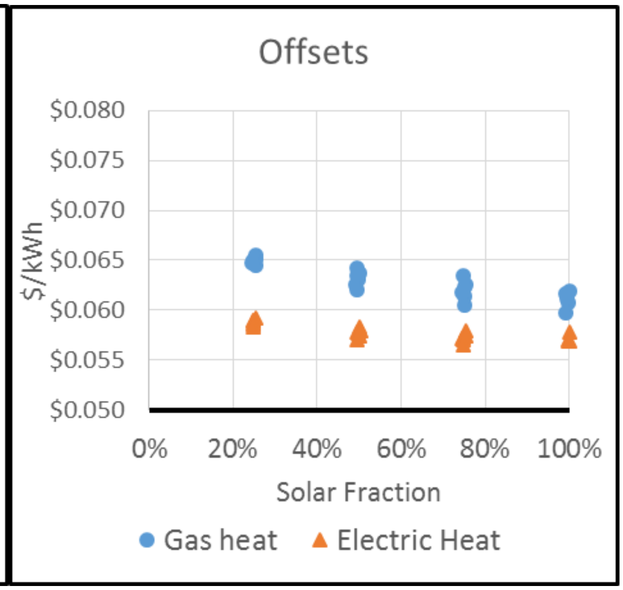


Figure 26. The hourly averages of LMP and customer energy usage. Also shown is the overall average LMP. Note that, in general, daylight hours are above the overall average, while nighttime hours are below it.





Figures 27 and 28. Weighted average costs for exports, and weighted average costs for offsets. Note that the costs of offsets are higher than the costs of exports for gas heat customers for systems with solar fractions of 50% or less. Exports of electric heat customers have a higher weighted average cost than their offsets for all electric heat scenarios.

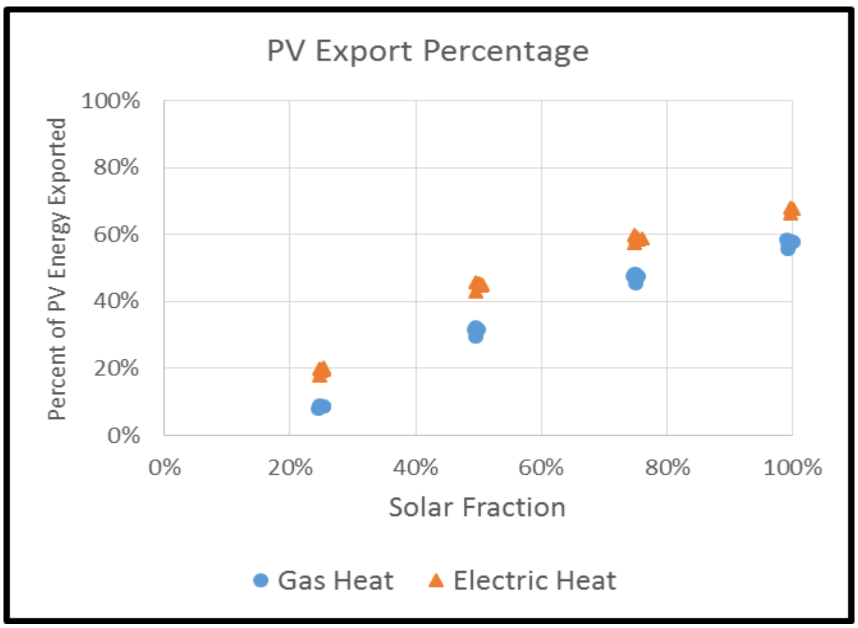


Figure 29. Percentage of PV generation that is exported. Customers with electric heat consistently export a greater proportion of their PV production than customers with gas heat.

However, the gas heating customer with a 100% solar fraction is a source of wholesale value in one crucial way. Under NC's net metering rules, any exports that remain as credits on a customer's bill at the end of May, after all possible offset scenarios are exhausted, are forfeited to the utility without compensation. Not only does DEC retain the retail value of those forfeits as covered above, but it does so without having to pay for those generation costs. By looking at the total value of the exchange of wholesale generation costs (Figure 29) and the difference between exports' generation costs and offsets' generation costs (Figures 25 and 27), one can arrive at the wholesale cost of the forfeited exports. For this gas customer, the difference between his exports' costs and his offsets' costs were roughly \$0.005/kWh per year, while the total value of his exchange of wholesale value with the utility was about \$0.014/kWh. This means that his forfeitures represented a wholesale value equal to \$0.09 for every kilowatt-hour of PV that he exported. When one considers that this customer was a net exporter of energy in May, it makes sense that he would not be able to realize the benefit of those exports, and that they would be donated to DEC without compensation.

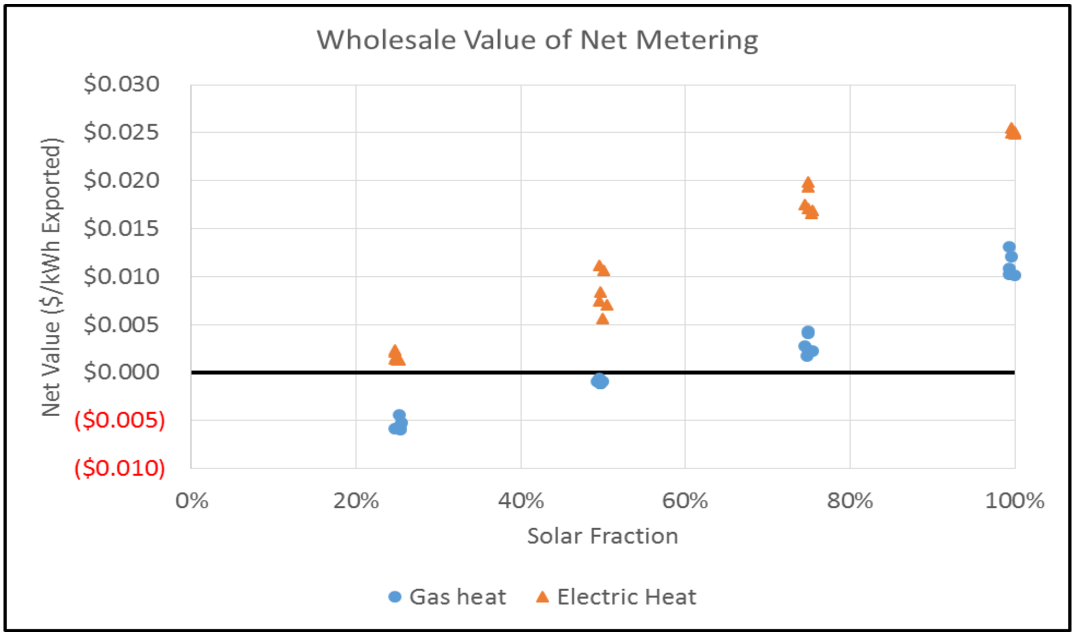


Figure 30. Value of the exchange of wholesale value between a net metering customer and DEC. Value is given as dollars per kilowatt-hour of PV energy that was exported onto the grid in the scenario. Note that electric heat results for systems with a solar fraction greater than 50%, and gas heat results with a solar fraction of 100%, are higher than $0.01/kWh.

Although taking a common sense approach to understanding net metering as it applies to the broad trends of wholesale price and customer energy use is useful, there are situations that are perhaps less intuitive. The greatest example of this is that the price range for LMPs in this study is enormous—the great majority of the hourly LMPs are below $0.10/kWh, while the highest 10% of LMPs ranged from $0.10/kWh to almost $1.00/kWh. These are the prices that are widely recognized as driving utility investment strategies, as was touched upon in Chapter 2 (USEIA, 2012). A utility might want to profit from those high prices, or it might want to build to lower those prices, but in either case those times known as peak demand play a large part in utilities' plans regarding generation capacity.

If a net metering customer is providing electricity during times of peak demand, he is providing a valuable service that might get averaged out in the big picture. Even if the customer is not exporting his PV energy, he is reducing the peak demand that the utility has to provide to the grid as a whole, which lowers costs for all ratepayers. My data suggested that there was a PV resource available for 70% of the top 1% of the hourly LMP records in my study (Figures 31 and 32). Furthermore, 80 of the top 100 hourly LMPs coincided with solar PV resource availability. Although I did not calculate the values associated with these hourly records individually, these statistics indicate that net metering customers provide a service beyond the raw exchange of wholesale value with the utility.

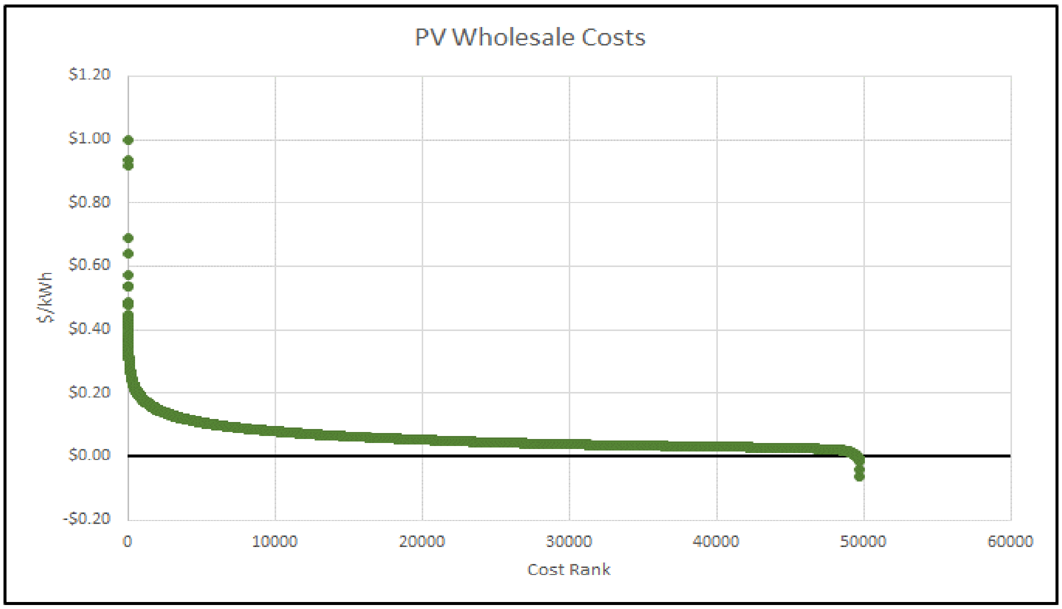


Figure 31. LMPs that were coincident with solar PV availability. The top 10% are drastically higher than the rest of the results.

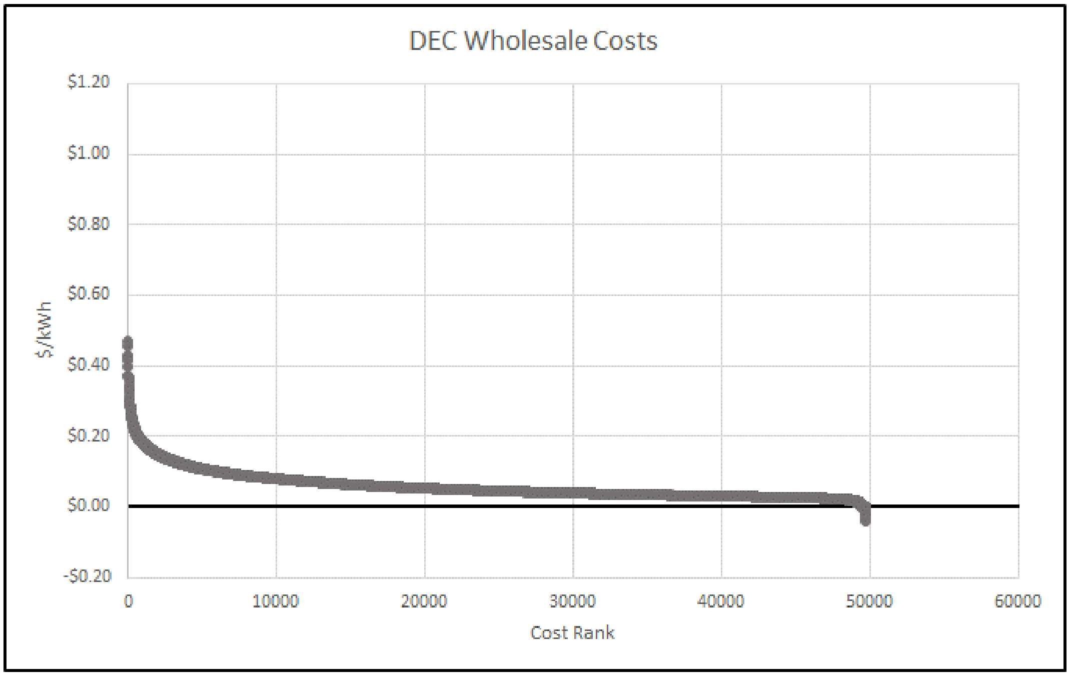


Figure 32. LMPs that were not coincident with any solar PV availability. The highest LMP was half that of the hours that had PV availability.

Net Value

To summarize, PV exports by net metering customers have been shown to be a source of benefit, not cost, for DEC and other ratepayers. This is due to the favorable timing of PV generation: it occurs when retail rates are highest, and when wholesale generation costs are above average. The value of the exchange of value between a net metering customer and DEC has been shown to be largely affected by the customer's energy usage pattern, by the solar fraction of his energy use, and finally, to a lesser degree, by the orientation of his PV system.

These wholesale and retail results support the larger result, which is that the net exchange of value between a net metering customer and DEC is, in most cases, a benefit for DEC (Figure 33, Tables 7 and 8). Furthermore, the favorable alignment of solar PV with customer energy usage and electricity prices means that what costs *are* imposed upon DEC are truly miniscule, and might be overshadowed by the benefits of a distributed resource that provides free energy at times of peak system demand.

The most beneficial arrangement that was studied was a net metering customer with electric heat and a PV array oriented to 150° with a solar fraction of 100%. This scenario provided $0.057/kWh of PV energy exported onto the grid per year, on average (Table 2). That is a very significant amount, and over half of it comes from the exchange of retail value that has been unaccounted for in the literature thus far. This system exports a great deal of peak energy in the winter and spring, and many of these exports are forfeited at the end of each May.

The scenario that burdened DEC with the greatest cost was any system where the customer had gas heat, a 25% solar fraction, and a PV array that was biased towards afternoon production. The combination of these three conditions incurred a cost of $0.006/kWh of PV exports per year, on average (Table 7). To put this to scale, all of these systems were around 2.5 kW in capacity, which resulted in a total cost incurred upon DEC of about $2 per year. For comparison, Duke Energy Corporation, of which DEC is a part, had an operating revenue of $23.9 billion in 2014 (Duke Energy Corporation, 2014). It would take a great many 2.5 kW net-metered PV systems to make much of a dent in that number. To ask every net metering customer in NC to pay a fee to compensate DEC for that $2 per year is not acting out of a desire to protect other ratepayers, On the face of this evidence, it may be possible that net-metered PV is beneficial for both net metering customers and their serving utility. The possibilities for strengthening this symbiotic relationship should be investigated further.

Table 7. *The Net Value of PV Exports for Net Metering Customers with Gas Heat*

PV Orientation	Net Value of Exported PV Energy 25%	50%	75%	100%
150°	-$0.004	$0.016	$0.025	$0.039
170°	-$0.005	$0.013	$0.024	$0.040
180°	-$0.005	$0.011	$0.023	$0.039
190°	-$0.006	$0.009	$0.022	$0.039
210°	-$0.006	$0.006	$0.022	$0.040
Storage	-$0.006	$0.004	$0.020	$0.040

Note. Net Value is expressed as dollars per kilowatt-hour of PV energy that the net metering system exported. Column percentages refer to solar fraction of customer energy use.
[a]See Chapter 3 for details about storage simulation. Array has azimuth of 180°.

Table 8. *The Net Value of PV Exports for Net Metering Customers with Electric Heat*

PV Orientation	Net Value of Exported PV Energy 25%	50%	75%	100%
150°	$0.010	$0.022	$0.043	$0.057
170°	$0.008	$0.024	$0.043	$0.056
180°	$0.007	$0.023	$0.043	$0.055
190°	$0.006	$0.024	$0.043	$0.053
210°	$0.005	$0.028	$0.044	$0.052
Storage[a]	$0.004	$0.028	$0.044	$0.051

Note. Net Value is expressed as dollars per kilowatt-hour of PV energy that the net metering system exported. Column percentages refer to solar fraction of customer energy use.
[a]See Chapter 3 for details about storage simulation. Array has azimuth of 180°.

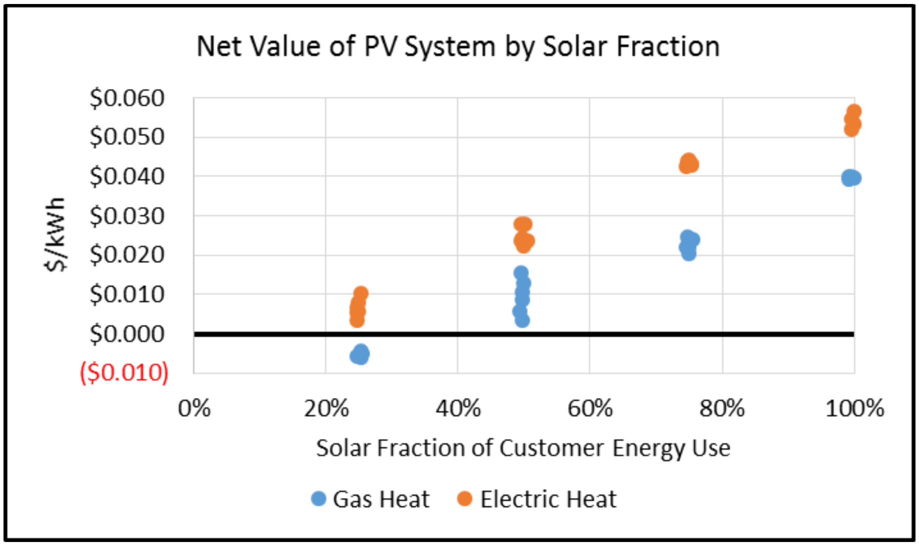


Figure 33. Net value of the exchange of value between a net metering customer and DEC. Each heating system shows an increase in the net value of exports as the customer's solar fraction increases. The results for a gas heated customer at 50% solar fraction showed the most variability in results. This variability is due to PV array orientation. Orientation does not appear to cause significant variability at other solar fractions.

Discussion

The benefits of this exchange are largely found in systems that are greater than five kilowatts in capacity. The vast majority of residential net metering systems that were applied for in 2014 were around five kilowatts in size; in fact, of the 234 applications for a net metering connection in 2014, only thirteen were larger than ten kilowatts (Duke Energy Corporation 2014b). These 234 systems do not represent a great amount of potential benefit to DEC. At the same time, it is not evident from this research that significant costs would be imposed on DEC by these customers.

As was discussed in Chapter 3, this method of ascribing value to the exchange of wholesale costs is somewhat inaccurate due to the nature of net metering. The exchange of value is an accounting practice, not a measurable event, because offsets are done on paper and have no physical characteristics. I have attempted to ascribe a physical reality to offsets by linking them to the weighted average cost of what the customer does consume; however, this was solely my solution to this problem, and is not necessarily the best solution.

Unfortunately, if someone used a different method to estimate the generation costs associated with the energy that a net metering customer offsets, their results for the exchange of wholesale value would likely be different than mine. However, I have used the weighted average cost of imports to most closely reflect the actual costs that are inflicted on DEC, and calculating a different value would require much more sophisticated models of the DEC's generation profile. The appropriateness of this method is supported by the fact that the offset costs differ for two customers with vastly different electricity consumption profiles: the customer who used electric heat imposed very different generation costs on the utility than the one who used gas heat. While the exact value produced may not be perfect, at least my method reacts in the appropriate way to customer usage inputs.

Conclusions

The results of my study indicate that the exchange of value inherent in net metering provides a subsidy to DEC in some scenarios. This subsidy is negative or nearly zero at small solar fractions, and increases with the solar fraction of the net metering system.

The exchange of *retail* value provided a subsidy to the utility at all but the smallest solar fractions tested in my study. This exchange of retail value is greater for customers with significant electric heating loads. The portion of this exchange attributable to forfeited customer exports increased in significance with solar fraction, and was present in all systems tested with over 50% solar fraction. The forfeitures were particularly pronounced for customers who used electric heat. Forfeitures represented over 50% of the subsidy from the exchange of retail value for all systems with a 100% solar fraction. The orientation of the customer's PV array had some effect on the exchange of retail value in systems with a 50% solar fraction

The exchange of *wholesale* value provided a subsidy to the utility in all but the smallest systems tested in my study. This subsidy was most pronounced for customers who used electric heat, presumably because they imported much more low-value, nighttime energy than high-value, daytime energy. The orientation of the customer's PV array had little effect on the subsidy from the exchange of wholesale value.

The net balance of the exchange of value seemed to be most dependent on the percentage of PV energy that the customer exported onto the grid, with the subsidy from the exchange of value increasing with the percentage of PV exports from total PV energy generated.

These results provide a useful baseline to discuss the other costs and benefits of distributed solar PV in a utility grid. These results suggest that net-metered PV systems usually only export the highest-value energy, and allow customer-generators to consume low-value grid energy. However, the effects of large penetrations of distributed solar PV are larger than this research's scope, and include such benefits as the reduction of transmission losses, the reduction of renewable energy purchases for the utility, the reduction of greenhouse gas emissions, and the possible reduction of peak grid electricity demand. There are also costs that have not been considered in this research, such as the cost of managing a large amount of intermittent, non-dispatchable generation, the standby capacity that would be necessary to provide stable grid power with large penetrations of PV generation, and the increased administrative costs for utilities to manage net metering customers.

However, my research suggests that net metering should not necessarily be considered to lower utility revenues out of hand. In some cases, such as when a customer has electric heat and a large solar fraction of his energy use, net metering provides a substantial subsidy to the utility. This suggests that utilities could view distributed, net-metered PV as an asset rather than a liability and, in light of all its other benefits, could seek to incorporate net metering more synergistically into their business model. For example, DEC could enter into the rooftop solar business and own the solar panels on top of a customer's roof. This arrangement would allow DEC to benefit from the high-value energy provided by the PV system, and would free DEC to offer less-than-retail rates for the solar energy to the customer in exchange for ownership.

The results of this study also indicate that customers with a large solar fraction donate a considerable amount of value to the utility by forfeiting energy credits at the end of the utility year. Some states require the utility to offer compensation for those credits (www.dsireusa.org). My results suggest that such a change to North Carolina's policy could be appropriate—the only customers in my study who forfeited any energy also provided a considerable subsidy to the utility per year, at both the wholesale and retail level. Such a change in policy could encourage more residents to invest in rooftop solar.

As for my research hypotheses, my results indicate that net metering provides a benefit to DEC in most, but not all, scenarios. The relationship between PV energy generation and the export of PV energy is much more dependent on the customer energy use profile than other factors; however, at solar fractions of 50%, the orientation of the PV array had a significant effect on the timing of PV exports. This research suggests that if a net metering customer uses his system to export PV energy during the day in order to offset large amounts of nighttime energy, there is likely to be a benefit for DEC. If the customer has an energy usage profile that is instead driven by summer afternoon cooling loads, then the subsidy is less pronounced. However, in all scenarios it was clear that the PV system preferentially generated electricity during times of peak retail prices and above-average wholesale prices. This relationship was particularly evident for customers who had a heating-driven electricity usage profile.

Further Research

The most necessary research that should follow this study is research that uses the same methodology but uses actual measured customer energy usage and PV energy generation, and that references utility generation costs for the chosen study area. Although this research indicates a positive net value of net metering for a utility, it does so using modeled data, and the validity of these findings would be bolstered by replicating the method with actual data. The method should also be extended to consider large net metering systems, since North Carolina recently raised the cap on system sizes to one megawatt.

The most interesting result, in my opinion, was that the average cost of imports for customers with electric heat was lower than that of customers with gas heat. This suggests another effect of distributed solar generation and net metering that has not yet received much attention in the literature, which is its ability to suppress mid-day energy prices. Researchers at Lawrence Berkeley National Laboratory have recently published a study on the potential price effects that large penetrations of PV could have (Darghouth, Barbose, & Wiser, 2014), and this research provides support for their position that solar PV could lower mid-day electricity prices. This benefit and its consequences for utilities and ratepayers should receive further attention.

Similarly, this research did not investigate fully the relationship between a net-metered customer with PV and peak utility electricity demand hours. These hours have an outsized effect on energy generation strategy, and it would be valuable to examine in further detail what value a net metering customer provides with his solar PV generation during those times.

Finally, this model and method could be employed to explore different utility rate structures and customer usage patterns. Rather than attempting to model actual events, this method could be used to explore the benefits of redesigned rates that take advantage of PV generation, or rates such as real-time electricity pricing that increase customer elasticity in relation to system energy demand. Even though the current net metering model does not impose a cost on DEC and other ratepayers, solar advocates and legislators could be more positive about finding ways to leverage the opportunities that distributed renewable energy presents into benefits for the entire state of North Carolina.

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Vita

Eric James Neff was born in Cullowhee, North Carolina, to Jeff and Randi Neff. He graduated from the University of North Carolina at Chapel Hill in May 2007. He spent several wonderful years after graduation in Cullowhee where he became an outdoorsman, overcame his fear of whitewater, had life-changing experiences leading teens through the woods, and got to know his parents better.

He enrolled in the Department of Technology and Environmental Design at Appalachian State University in August 2013, and began a study towards a Master of Science degree in Appropriate Technology. The M.S. was awarded in May 2015.

Mr. Neff was born in the mountains, and he is proud to have graduated as a Mountaineer. He is also a proud uncle, and he is currently teaching and traveling in the Appalachian Mountains and in parts unknown.