DISSERTATION

RENEWABLE ENERGY IN COMMUNITY:

ECONOMIC IMPACTS OF THE GRID

Submitted by

Benjamin Alexander Saarloos

Department of Systems Engineering

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Doctoral Committee:

Advisor: Jason Quinn

Thomas Bradley
Jesse Burkhardt
Daniel Olsen

ABSTRACT

RENEWABLE ENERGY IN COMMUNITY:

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The U.S. energy grid is a complex system that supports everyday lives. Grid energy has traditionally flowed in one direction from large, centralized power plants through transmission and distribution networks to corporate and residential consumers. However, with a growth in renewable energy systems (RES), energy flow has begun to take on a more bi-directional character with distributed generation, including excess energy generated by consumers being fed back to the energy grid. The breadth of individual energy use impacts and societal benefits attributed to growth in RES calls for analysis and development of RES on the community scale. Beyond the physical energy connection it provides, the grid can serve as an economic mechanism whereby RES can be sustainably developed through the grid, rather than an alternative to the grid.

Measures have been developed to advance RES toward sustainability targets, recognizing that the grid plays an important enabling role. Net-zero energy is a classification system designed to reduce energy consumption in buildings and communities in support of climatic goals to reduce greenhouse emissions. A hierarchy of renewable energy supply options is established with a preference for on-site renewable energy over off-site supply options. Value of Solar (VOS) is an electric rate design mechanism intended to determine the true value of solar photovoltaic (PV) generated electricity. Beyond the obvious benefit of fossil fuel saved, VOS includes cost savings associated with avoided capacity, transmission & distribution cost deferral, and environmental benefits. Net-zero energy and VOS methodology are both identified as sustainability measures within a broader RES design process.

Sustainable RES design recognizes that harmonizing economic, environmental, and social interests is a community effort. Case-studies present an opportunity to further develop a consistent set of design principles while simultaneously presenting unique and important results. In this work, a net-zero energy analysis is conducted for the National Wester Center in Denver, CO. A coupled energy and economic analysis demonstrates the critical role played by the grid in the economic feasibility of achieving net-zero energy, as well as the mutual benefit of on-site energy storage. A VOS case study is performed for Sioux Center Municipal Utilities in northwest Iowa leveraging five years of municipal power consumption coupled with real PV electricity generation data. A dual optimization approach develops an electric rate structure that best aligns with and incentivizes development toward optimal VOS design. Together, these studies affirm that while local technical solutions and optimal designs may differ, the principles of sustainable design can be applied and followed consistently such that RES can grow and flourish in communities across the globe.

ACKNOWLEDGEMENTS

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Chapter 1. Background

1.1 The U.S. Energy Grid System

The U.S. energy grid can be classified as an engineering system delivering an output of usable energy to consumers from various sources that include inputs of fossil and nuclear fuels as well as renewable energy resources [1]. Major sub-systems include conversion, distribution, and storage; each of which is influenced by energy efficiency measures, utilities and energy service providers, and societal, institutional, and environmental factors. Traditionally, energy has flowed in one direction from large, centralized power plants through transmission and distribution networks to corporate and residential consumers. However, with a growth in renewable energy systems (RES), energy flow has begun to take on a more bi-directional character due to the development of numerous small, distributed systems in which excess energy generated by residential and corporate consumers is fed back to the energy grid.

Changes in the U.S. electricity industry have been linked to six key factors that are driving a paradigm shift in resource planning [2]: 1) federal and state environmental and energy policies, 2) greater reliance on natural gas-fired generation coupled with continued uncertainty in natural gas prices, 3) declining renewable energy technology costs, 4) flat or declining load growth, 5) changing customer preferences, and 6) improvements in, and greater deployment of, information and communications technology in electricity systems. Reviewing this list of factors, it is clear that 1), 3) and 5) are largely related to growth in RES. While currently comprising just over 9% of total U.S. electric energy consumption, wind and solar combined are projected to triple in terms of total electricity sector contribution from 2019 to 2050 [3]. Given this large growth projection, it is important to consider how to best integrate this RES growth with existing generation and transmission infrastructure.

As shown in Figure 1-1, the electric generation in the U.S. has changed dramatically over the last 30 years, shifting from a majority of coal generation to natural gas being the leading current generator fuel at 39%. Wind and solar have grown from near zero to 9% in 2019, meaning the EIA projection of tripling will push it to nearly 30% by 2050. However, as shown in Figure 1-2, there are large geographical variations in generation as evidenced by the difference between California with 7% wind, 15% solar and no coal, compared to Iowa with 42% wind, 36% coal, and negligible solar. The geographical differences are further illustrated in Figure 1-3 noting that the electric generation of states comprising the Midcontinent Independent System Operator (MISO) regional transmission organization differs from the U.S. total with more coal and wind energy, but near zero solar contribution.

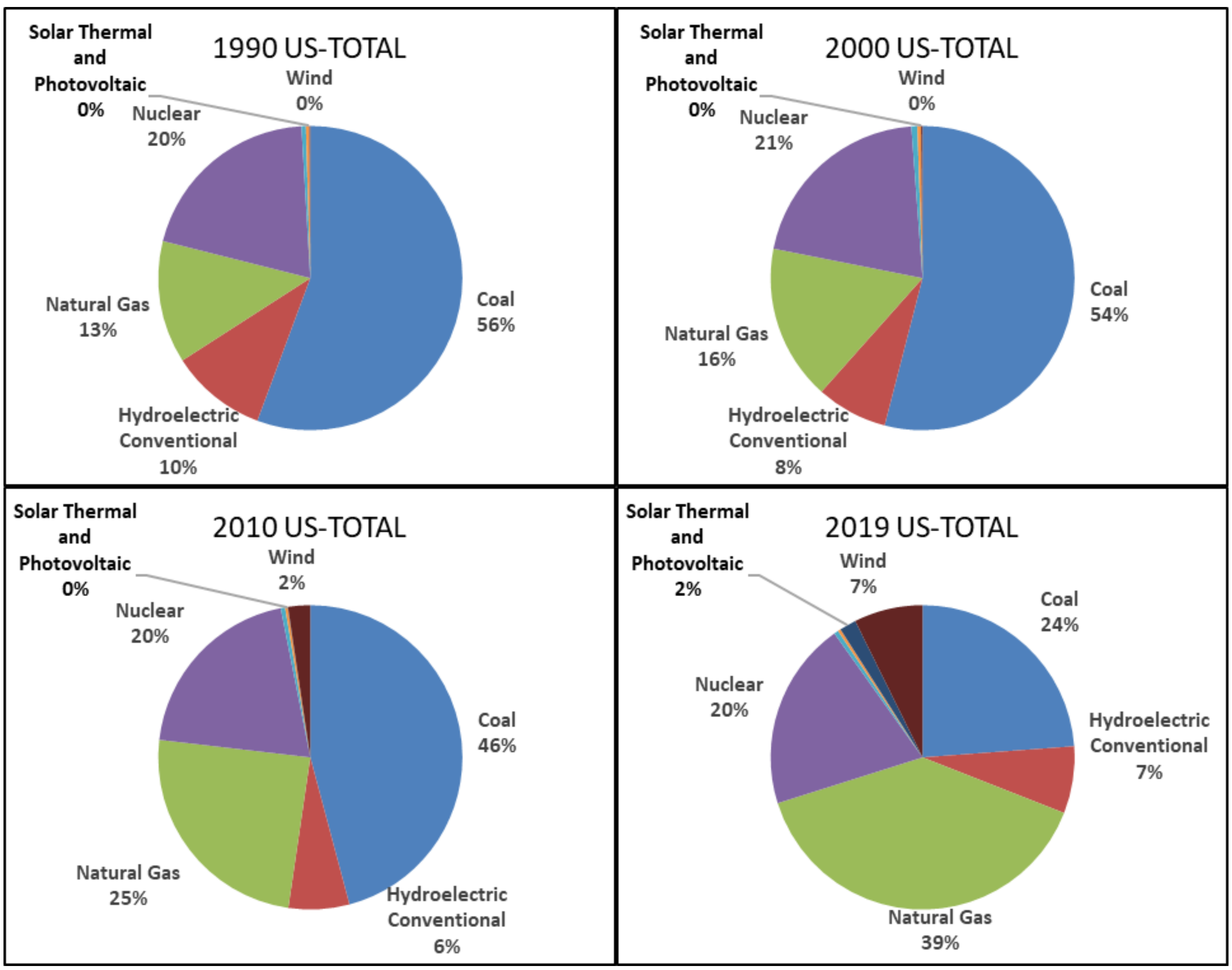


Figure 1-1. Electric Generation in the U.S has shifted dramatically in the last 30 years from a majority of coal generation to a much higher contribution of natural gas and the growth of renewables to a total of 9% wind and solar renewable resources [4].

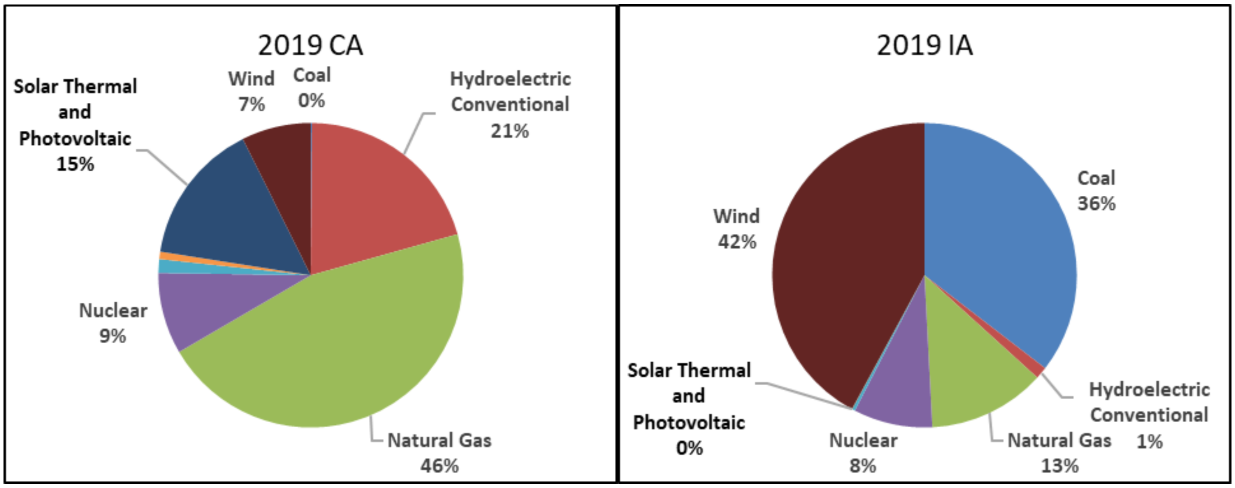


Figure 1-2. Within the U.S there are large geographical variations of electrical generation. In California, wind and solar comprise 22% of generation and natural gas has replaced all coal generation. In Iowa, wind is the leading generator, while coal generation remains high and solar produces less than 1% of generated energy. [4].

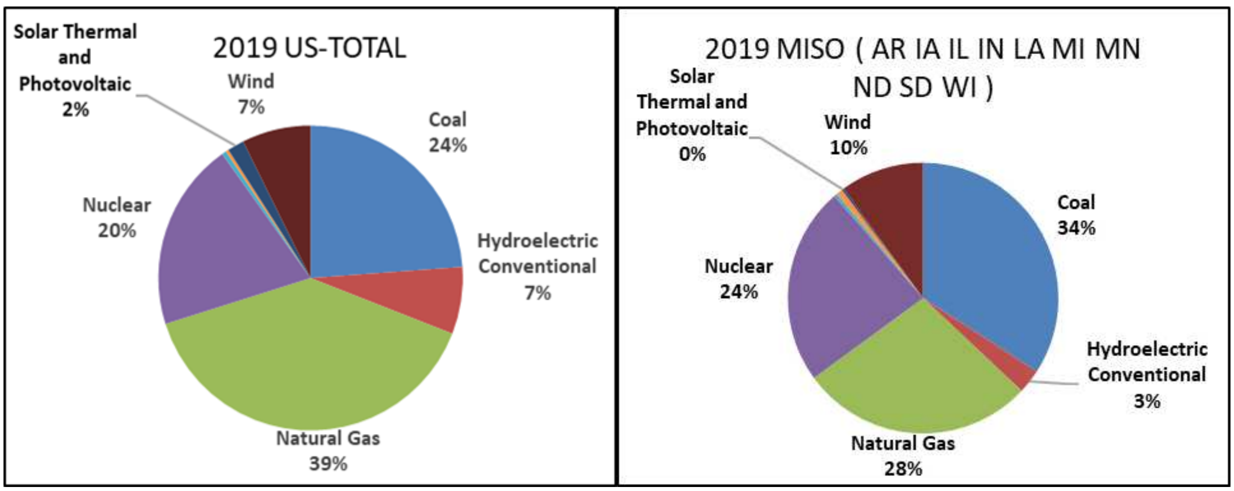


Figure 1-3. The electric generation of states comprising the Midcontinent Independent System Operator (MISO) regional transmission organization differs from the U.S. total with more coal and wind energy, but near zero solar contribution [4].

The MISO state generation portfolio of Figure 1-3 reflects the notion that the upper Midwest is considered wind energy country and is not historically known for solar energy development. However, recent analysis suggests that a mix of solar and wind additions would be more beneficial going forward from a useful energy perspective than using wind alone [5], and wind and PV can also complement one another in daily and seasonal trends [6]. Thus, a motivating aspect of the current work is to specifically analyze the grid impact of increased PV penetration in Sioux Center, Iowa. The analysis is focused on local demand and generation data for Sioux Center Municipal Utilities (SCMU), which services more than

2700 electric customers including mix of residential, commercial, and industrial sites. In this way, a local analysis of SCMU can be representative of the larger upper Midwest geographical area.

In aspiration towards a 100% renewable energy future, Lund [7] identifies three implementation phases for renewable energy systems. The introduction phase is characterized by marginal installations of renewable energy where renewables are a small share of total energy, while the large-scale integration phase is where further increases in renewable energy will have a varying hour to hour impact on the system. In the 3rd 100% renewable energy phase, new investments in renewable energy must be compared not to nuclear or fossil fuels, but to other renewable technologies including conservation, efficiency improvements, and storage and conversion technologies [7]. Given the current 9% of electricity in the US is currently generated from wind and solar, the U.S. finds itself squarely in the large-scale integration phase. Broad studies of the Eastern and Western electrical interconnections of the U.S have concluded that up to 35% of renewable energy penetration can be integrated without extensive infrastructure changes [8,9] and would be accompanied by a 25-45% reduction in carbon emissions [8]. Given the current projection of wind and solar to triple by 2050 [3], it is important to consider how to guide RES design through and beyond this large-scale integration phase.

1.2 Systems Engineering: a Sustainable Approach

The function of systems engineering is to guide the engineering of complex systems [10]. Systems engineering takes a top-down approach to view the system as a whole, emphasizing a better and more complete effort in the initial definition of system requirements [11]. A key method for developing an appropriately broad set of requirements is a stakeholder analysis. Table 1-1 lists the desires for six key stakeholder groups of the electric grid: RES generator, RES industry, electric customer, electric utility, policy maker, and society. Some of the desires span multiple stakeholder groups such as reliable power at low cost and providing shareholder value. Economic desires can be seen from both an individual perspective (return-on-investment, shareholder value), as well as the broader societal desire for a stable economy. The regulatory requirements of the utility are often viewed as cost, while they are set by policymakers to enable the improved air/water quality and reduced greenhouse gas emission desires of society. Policymakers also seek to provide mechanisms such as incentives, subsidies, and tariffs to further meet and advance environmental goals that benefit society but may not be adequately supported in the existing electricity market.

Table 1-1 Renewable Energy System (RES) stakeholder objectives and desires [12–14]

Stakeholder	Objectives/Desires
RES Generator	Predictable return-on-investment Compensation for benefits provided Meet Society renewable goals
RES Industry	Grow/support RES generation Provide shareholder value
Electric Customer	Reliable power at low cost Support environmental goals
Electric Utility	Provide electricity reliably, safely, and at low cost Reduce/eliminate cross-subsidization in electric rates Provide shareholder value Meet regulatory requirements
Policymaker	Reduce/eliminate cross-subsidization Meet/support environmental goals for Society Provide mechanisms to meet RES mandates
Society	Improved air/water quality Reduced greenhouse gas emissions Stable economy

These varying stakeholder desires can be analyzed in what has been defined as the triple bottom line of sustainability [15,16] depicted in Figure 1-4. In this view, sustainability is seen as harmonizing economic, environmental, and social interests. The interrelationship of these three dimensions of sustainability implies that actions or pursuits in one dimension will inevitably influence the others, which leads to a number of concepts in regards to sustainability [15–17]. Sustainability includes integrating the short-term and long-term, consuming the income and not the capital, and considering local and global perspectives. Applied to the electric grid, this means balancing short-term social, economic, and energy needs against longer-term environmental impacts. Consuming income and not the capital relates to over-spending non-renewable, limited resources (such as fossil fuels) in such a manner as to sacrifice the future (our capital) to meet immediate desires. Considering both local and global perspectives assesses direct and indirect impacts of energy decisions on local, national, and international communities. Thus, sustainability spans broadly in both temporal and geographical terms.

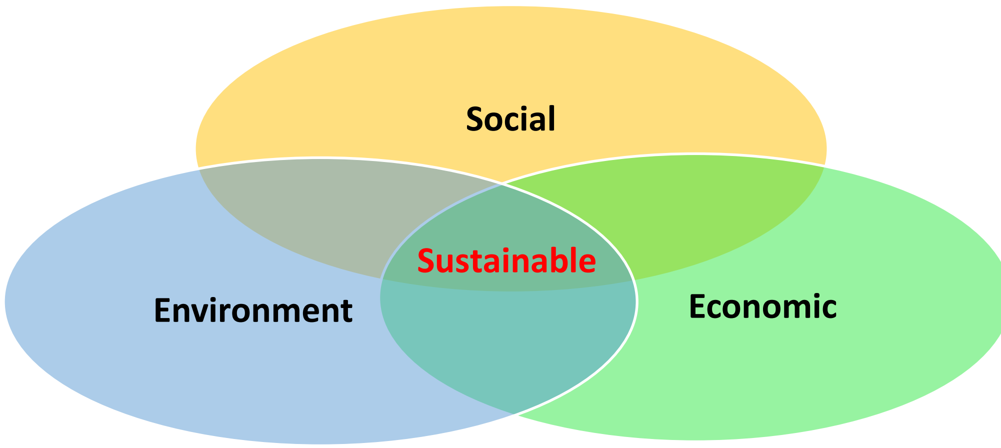


Figure 1-4. Social, Environment, and Economic dimensions of the Triple Bottom Line of Sustainability [15]

The various stakeholder desires of Table 1-1 can be categorized into system design considerations of systems engineering [11]. Grid reliability must be maintained despite fluctuating and intermittent RES generation, which calls for system design considerations of flexibility, availability, supportability, and adaptability. Improved air/water quality calls for the system design considerations of pollutability (i.e. CO2), environmental sustainability, recyclability, and disposability. Sustainability in systems engineering further considers the impact of waste throughout the product life cycle including development, production, operation, and disposal. Beyond the fossil fuel environmental impacts offset by renewable energy generation, one much also consider life cycle assessments of the renewable generation and associated storage technologies themselves, such as PV panels and batteries [18–20]. These systems also have life cycle emissions, albeit much lower than traditional fossil systems.

Stakeholder participation is also key in sustainability [15]. This goes beyond simple communication, and requires active participation to jointly define problems, generate possible solutions, and collaborate to implement them. Such a process requires transparency in communication, ethical behavior in implementation, and accountability in being open to other stakeholder opinions and taking responsibility for actions. Two key goals in sustainability are risk reduction and eliminating waste. Sustainability risk is broader than simple commercial risk and includes social and environmental risks, such as safety and pollution. Waste can be associated with time, human resources, natural resources, or other environmental assets. The breadth of possible sustainable energy solutions requires a systems engineering approach with active participation from a broad stakeholder base. This calls for development of RES in community leveraging systems engineering principles.

1.3 Renewable Energy in Community

The North American electric grid has historically been developed on the principles of centralized generation from fossil fuel sources. By definition, the grid physically connects regional communities as local electricity grids are interconnected through a structure of major interconnections operated by independent system operators (ISOs) and regional transmission organizations (RTOs). RTOs also function as balancing authorities to monitor demand and control supply such that safe and reliable operation of the power system is maintained. The importance of grid reliability is evidenced by the existence of the North American Electric Reliability Corporation (NERC) which performs annual performance analyses and long term reliability assessments [21,22] as part of their mission to assure effective and efficient reduction of risks to the reliability and security of the grid.

In several ways, RES represents a discontinuity in the historical design of the electricity grid due to their inherent fluctuating intermittent nature, growth in small-scale decentralized generation, and unpredictability. However, studies have shown that the variability of RES can be substantially reduced by increasing the size of the geographic area over which the wind and solar resources are drawn [8]. Additionally, in a given RES, there is an inherent correlation between weather conditions, distributed energy resource (DER) generation and electrical load [23]. Thus, DER generation is naturally developed at smaller community scales, while its societal impact extends beyond those local community borders.

In this manner, beyond the physical connection of energy supply, the grid plays an important economic enabling role in the advancement of RES.

In the advancement of RES design, Lund notes the complexity of the broad variety of measures that must be combined to reach sustainability targets, while each individual measure must be evaluated on its own and coordinated with the overall system [7]. With respect to the electric grid, the key consumer measurements are energy consumption rate and electricity price. Energy consumption and electricity price are coupled in that the cost to delivery energy depends on the energy flow rate (i.e. power), and the variation of that rate over time. The continued growth of RES is dependent on recognizing that the total cost of electricity is greater than simply the consumable fuel prices, capital expenditures, and operating costs to produce it. A sustainability view considers the scarcity of non-renewable resources for future generations as well the environmental impacts of combusting fossil fuels. A broader socio-economic approach is proposed to consider RES feasibility that includes such external costs as well as the impacts of job creation and industrial innovation [7]. Since currency economic terms are the best understood measurement scale, efforts have been made to convert more qualitative external costs into currency equivalents, such as defining the social costs of carbon [24].

Problem Statement: The breadth of individual energy use impacts and societal benefits attributed to growth in RES calls for analysis and development of RES on the community scale. Beyond the physical energy connection it provides, the grid can serve as an economic mechanism whereby RES can be sustainably developed through the grid, rather than as an alternative to the grid. This work investigates the economic impacts of the grid in optimizing two sustainability measures: net-zero energy districts and value of solar.

1.3.1 Net-Zero Energy Districts: Grid Supported Sustainability

In the United States, buildings are responsible for 40% of carbon emissions and consume 75% of grid electricity [25]. As such, sustainable energy building design has been a growing focus in the last couple decades. Net-zero energy is a classification system designed to reduce energy consumption in individual buildings as well as larger districts or communities in support of climatic goals to reduce greenhouse gas emissions. It follows a systematic sustainable design approach to energy by establishing a hierarchy of renewable energy supply options of first reducing site energy use through energy efficiency and demand-side renewable technologies, followed by preference for on-site renewable energy supply over off-site supply options [26]. A key goal is to maximize use of local community renewable energy sources. Net-zero energy is most often measured in terms of site energy consumed, but can also be measured as source energy used to generate the site energy, energy costs, or energy emissions [27]. Implicit in the goal of achieving net-zero energy is the recognition that energy generated from renewable sources (i.e. wind, solar, geothermal) benefits the larger community through reduced CO_2 and air pollutant emissions as well as conservation of limited fossil fuel resources. There are characteristics of renewable generation that represent challenges for net-zero energy districts, most notably intermittent generation.

Districts are collections of buildings which can be optimized on their own and in conjunction with each other. The optimization process brings together separate building performance simulation and optimization tools. Optimization is most commonly energy or economic related, but can also include building layout & form, construction, and thermal comfort [28]. Given the intermittent nature of many renewable energy resources, it is important to consider the dynamic load/generation energy mismatch of the district as well as balancing competing needs of self-sufficiency, investment cost, and reliability [29]. The mismatch between load and generation at the building level can be better managed when an aggregation of buildings is considered [30], including implementing specific strategies to improve load matching [31]. Energy storage is a technology to help manage this balance, and has been shown to offer a net-zero cost advantage over an equivalent system void of storage [32]. Some studies have concluded that traditional thermal storage is the only economically viable energy storage [33], but other economic analyses demonstrate the viability of lithium ion battery storage [34,35]. Implementation of storage as a district load-matching strategy can be complicated by the determination of its physical location and fairly assessing the distribution of installation and operational costs.

Campuses are districts of particular interest for net-zero energy because of the inherent relationship between buildings and the availability of open space. Previous efficiency-focused campus case studies have noted the difficulty of achieving net-zero in densely developed neighborhoods [36–38]. By contrast, the National Western Center (NWC) in Denver, CO, USA in is a 100+ hectare (250 acre) campus centrally located at the intersection of the South Platte River and Interstate-70. With a planned 1.8 million ft^2 of total building space, the NWC has previously been identified as a prime candidate to study the evolution of net-zero energy concepts from individual buildings to districts [25,39].

A significant challenge in relation to district energy system modelling is to provide simple tools that can support decision makers early in the design process at both the building and urban levels [40]. In this work, EnergyPlus [41], a popular building simulation tool [28], is used as part of an energy demand/production model with parameter optimization to understand the economic feasibility of district level net-zero energy. Levelized Cost of Energy (LCOE) is optimized as a function of variables defining the energy and economic relationship with the energy grid and further quantified for micro-grid scenarios that achieve grid independence.

The novelty of this work is advancing the development of net-zero energy districts by specifically investigating the economic impact of a key underlying net-zero energy assumption: the energy grid. Net-zero renewable energy deployment is investigated in terms of economic viability and grid energy dependence using the NWC as a case study. LCOE is calculated with and without energy storage and coupled with a variable buy:sell cost ratio for energy imported from and exported to the grid. The results quantify the required involvement of the energy grid for general economic feasibility

and demonstrate the positive impact of stored energy on reducing both LCOE and grid energy dependence.

The NWC net-zero energy analysis is summarized in Chapter 2. The NWC is undergoing a major redevelopment process with an emphasis on sustainability and a net-zero energy goal. The net-zero site energy analysis is performed on the campus leveraging on-site solar, thermal, and biomass based renewable energy sources. A coupled energy and economic analysis is performed to investigate and demonstrate the critical role played by the grid in the feasibility of achieving net-zero energy. The economic analysis is intentionally limited to business costs to characterize the direct economic costs associated with achieving net-zero energy, and in recognition that the environmental benefits are implicit in setting a net-zero energy goal.

1.3.2 Value of Solar: Recognizing Grid Benefits as well as Costs

Beyond the costs of installation and operation (i.e. LCOE), integrating RES onto the grid has additional cost impacts that need to be considered. Costs that arise from different physical impacts overlap, so treating different categories of costs as simply additive can be misleading [42]. It is helpful for understanding to divide integrating costs into three main categories that reflect three specific characteristics of RES: 1) balancing costs due to uncertainty and unpredictability, 2) profile costs due to variability of generation, and 3) grid costs due to location specificity [43]. A recent systematic review of integration costs revealed limited data on grid costs, noting solar grid costs are much less than wind since solar is often installed closer to its need [42]. Heptonstall and Gross [42] further concluded that upgrades to transmission and distribution networks are difficult to allocate specifically to RES variability.

Balancing costs are mainly operating reserves, which are typically less for solar than wind because the sun is more predictable [42]. The Western Wind and Solar Integration Study (WWSIS) reports that in the 30% renewable energy penetration case, the average variability reserve requirement does indeed double. However, with wind and solar on the system, it is often more economically favorable to back down thermal units rather than decommit them [8]. More specifically the study noted nearly a 1:1 correlation between increased solar production and reduced combined cycle production [44]. This results in increased up-reserves being available without additional capital costs. Furthermore, from an operational perspective, balancing area cooperation can lead to additional cost savings because reserves can be pooled [8]. For these reasons, no specific balancing costs are added in this analysis.

Profile costs thus emerge as the largest and most significant integration costs. These costs are linked to the temporal variability of RES with an uncontrollable output not necessarily correlated to demand [43]. Factors contributing to these costs are low RES capacity factors, and increased ramping and reduced load factors of conventional generation. These are not really costs by definition, but more accurately described as diminishing savings of displaced conventional generation. While it has been shown that the direct economic impact of cycling is small, the largest single factor of integration costs is the resulting reduced utilization of capital embodied in thermal plants [43]. From a profile benefit perspective, adding solar PV can help make the system more reliable and/or reduce the cost of meeting peak demand [42], such that integration costs can even be negative at low (<10%) RES penetration [43]. In these cases, there is a strong correlation between PV output and summer daytime peaks.

Characterizing integration costs as additional expenses to be added to system generation costs has been described as a bottom-up engineering view of power system operation [42]. Economically, these integration costs represent the difference between the average electricity price and the market value of the renewable energy. There is also a temporal component to these costs as long-term integration costs are less because the grid adapts [43]. Total system costs with and without renewables can be calculated accurately, but calculating an “integration cost” that only includes the added cost the power system incurs dealing with the variability and uncertainty of wind and solar is much more difficult [45]. The best studies model security-constrained unit commitment and economic dispatch and account for errors of wind, solar, and load as well as actual output and consumption [45], as exemplified the WWSIS and ERGIS integration studies [9,46–48].

This work seeks to take a top-down engineering view of power system operation by analyzing the system load duration curve (LDC) before and after renewable penetration (residual LDC or RLDC) to characterize RES in terms of the value it adds to the system. From a mixed cost/benefit perspective, the aforementioned profile costs can be regarded as reducing the value of RES because they reflect diminishing avoided costs [43]. Instead of seeking to define a full system weighted LCOE to compare to other generation technologies, published RES LCOE can be weighed against this calculated value to gage the merit of installation. The methodology used to determine this value of PV added to the gird is called Value of Solar (VOS) [13].

VOS was developed as rate design mechanism intended to measure the true value of solar PV generated electricity. While there is ample data available on fuel and wholesale retail electricity costs [49,50], there is a lack of consensus on what renewable energy is worth. Beyond the obvious benefit of fossil fuel saved, VOS includes costs associated with avoided capacity, transmission & distribution cost deferral, and environmental benefits [13,51]. To date, most VOS studies have been leveraged to define a consumer energy rate for RES generation somewhere between the extremes of net-metering and displaced fuel costs. However, given the broad system considerations encompassed in the methodology, in this work VOS is leveraged as a system design benchmark.

Value of solar has been analyzed for utility scale PV for 10,000 U.S. locations from 2010 to 2017 using historical nodal electricity prices, capacity market prices, marginal power system emissions, and Typical Meteorological Year (TMY) weather data to classify the value of PV in terms of displaced energy, capacity, public health, and climate change [52]. The analysis assumed horizontal one-axis-tracking PV systems and concluded that the net benefits of utility-scale PV outweigh the cost across the majority of U.S. markets when a $50/ton social cost of CO_2 is included. Results are plotted geographically on a map of the US with average PV-generated revenue on the order of $100/kWac-yr over the 7-year time span, or an average value of approximately $0.042/kWh. It is noted that the data tends to be clustered in the Northeast, West (particularly California), and Texas. There is a notable lack of data in the upper Midwest region.

PV optimization studies have also been performed before. A non-constrained nonlinear optimization ('fminsearch' function in MATLAB [53]) was used to find the local maximum global hourly irradiation as a function of panel tilt and azimuth for locations across the continental U.S. Mapped results indicate an approximate optimum tilt of 37° from horizontal and azimuth 2° west of South (182°) for the geography of Northwest Iowa [54]. Noting that higher summer electricity prices tend to drive azimuth west and tilt towards the horizontal, a subsequent study compared PV energy peak to market value peak using TMY weather, inverter modelling, and time-of-use rates throughout the continental U.S. as a proxy for average local grid conditions [55]. Energetically the optimal azimuth was consistently within 10° of South for 90% of 1020 locations, while the max value of energy was found to shift more than 10° west of South for nearly half of the locations. Analysis of Austin, TX using locally measured solar irradiance data for 2012-13 found 1-7% higher energy value at 20-51° west of South azimuth angles [55]. The TMY data max energy and value azimuths for Northwest Iowa both remained within 10° of South, meaning the analysis did not find an economic incentive to significantly reorient the PV array.

The novelty of this work is to develop VOS as an optimization measure and analysis tool and simultaneously calculate specific VOS for the upper Midwest. By applying a top-down LDC/RLDC system analysis, integration costs are defined from a value perspective that capture the changing value as RES penetration increases on the grid. Defining VOS in this way allows for PV system design optimization as well as a benchmark against which different electric rate structures can be analyzed and compared. The methodology applied is considerably simpler than a full capacity-expansion

system model, yet it provides key insights and trends consistent with findings from such studies. As presented, this VOS methodology is an easy-to-use yet meaningful tool for municipalities and smaller utilities to evaluate investment in and guide design of PV in their local community.

A VOS case study is performed for Sioux Center Municipal Utilities in northwest Iowa and outlined in Chapter 3. The study leverages five years of municipal power consumption coupled with real PV electricity generation data. Two optimizations are performed in the study. The first is an optimization to maximize VOS through the orientation of the PV system (tilt, azimuth). The second optimization minimizes net energy costs based on the rate structure of the utility. Multiple rate structures are explored with a final proposed alternative rate structure that best aligns rate structure and VOS optimized designs. The analysis is repeated with TMY data to reveal economic and performance advantages of PV installation based on real production data that are not fully realized in a TMY data analysis.

Chapter 2. Net-Zero Energy Districts and the Grid: An Economic Feasibility Case-Study

Given the enormous impact of buildings on energy consumption, it is important to continue the development of net-zero energy districts. Opportunities for energy efficiency and renewable energy on a district level exist that may not be feasible in individual buildings. Due to the intermittent nature of many renewable energy sources, net-zero energy districts are dependent on the energy grid. The novelty of this work is to quantify and optimize the economic cost and grid independence of a net-zero energy district using the National Western Center (NWC) in Denver, CO, USA as a case study. The NWC is a 100+ hectare campus undergoing a major redevelopment process with a planned 170,000 m^2 of total building space, an emphasis on sustainability, and a net-zero energy goal. Campus plans, building energy models, and renewable energy performance models of on-site solar, biomass, and thermal renewable energy sources are analyzed in multiple energy scenarios to achieve net-zero energy with and without on-site energy storage. Levelized Cost of Energy (LCOE) is optimized as a function of variables defining the energy and economic relationship with the grid. Discussion herein addresses trade-offs between net-zero energy scenarios in terms of energy load, LCOE, storage, and grid dependence.

Research Question 1: How does the grid impact net-zero energy district design and operation?

Hypothesis 1: The grid enables net-zero economic feasibility and supports mutually beneficial energy storage.

2.1 Introduction

In the United States, buildings are responsible for 40% of carbon emissions and consume 75% of grid electricity [25]. As such, sustainable energy building design has been a growing focus in the last couple decades. Design includes performance goals such as net-zero energy, where efficiency gains are implemented such that the balance of the energy needs can be offset by renewable technologies [26]. More recently, zero energy has been expanded to “communities” [27], noting that larger districts provide opportunities for energy efficiency and renewable energy penetration that may not be feasible in individual buildings [25]. Zero energy district design principles have been outlined as a priority of maximizing: 1) building efficiency, 2) solar potential, 3) renewable thermal energy, and 4) load control [25]. While the goals may be consistent, how zero energy strategies play out in terms of technology and design are unique to each district.

Districts are collections of buildings which can be optimized on their own and in conjunction with each other. The optimization process brings together separate building performance simulation and optimization tools. Optimization is most commonly energy or economic related, but can include building layout & form, construction, and thermal comfort [28]. The interaction between buildings can impact both their design and performance, such that urban form generation models have been coupled with energy systems programs in energy-driven urban design [56]. Recently, multi-objective optimizations have been applied in case studies with simultaneous goals to minimize greenhouse gas, life-cycle cost, and net exergy deficit [57], or annualized cost and equivalent CO_2 emissions [32].

Given the intermittent nature of many renewable energy resources, it is important to consider the dynamic load/generation energy mismatch of the district and balancing competing needs of self-sufficiency, investment cost, and reliability [29]. The mismatch between load and generation at the building level can be better managed when an aggregation of buildings is considered [30], including implementing specific strategies to improve load matching [31]. Energy storage is another technology to help manage this balance, and has been shown to offer a net-zero cost advantage over an equivalent system void of storage [32]. Some studies have concluded that traditional thermal storage is the only economically viable energy storage [33], but other economic analyses demonstrate the viability of lithium ion battery storage [34,35].

Campuses are districts of interest because of the inherent relationship between buildings and available space. Previous efficiency-focused campus case studies have noted the difficulty of achieving net-zero in densely developed neighborhoods [36–38]. The National Western Center (NWC) in Denver, CO, USA in is a 100+ hectare (250 acre) campus centrally located at the intersection of the South Platte River and Interstate-70, and is one of six Zero Energy Districts Accelerator (ZEDA) participating partners previously identified as prime candidates to study the evolution of net-zero energy concepts from individual buildings to districts [25,39]. Attia et al. identify a large number of varying building simulation and optimization tools [28], while Allegrini et al. state that a significant challenge in relation to district energy system modelling is to provide simple tools that can support decision makers early in the design process at both the building and urban levels [40].

The novelty of this work is to advance the development of net-zero energy districts by investigating the economic impact of a key underlying net-zero energy assumption: the energy grid. Net-zero renewable energy deployment is investigated in terms of economic viability and grid energy dependence using the NWC as a case study. EnergyPlus [41], a popular building simulation tool [28], is used as part of an energy demand/production model with parameter optimization to understand the economic feasibility of district level net-zero energy. Levelized Cost of Energy (LCOE) is optimized as a function of variables defining the energy and economic relationship with the energy grid and quantified for micro-grid scenarios that achieve grid independence. The results quantify the required involvement of the energy grid for general economic feasibility and demonstrate the impact of stored energy on reducing both LCOE and grid energy dependence.

The NWC is in the midst of a major redevelopment process with a planned 170,000 m^2 (1.8 million ft^2) of total building space and an emphasis on sustainability as evidenced by defined goals to minimize annualized energy demand, maximize installed renewable energy generation potential, and couple site and building operations to maximize energy efficiency performance with low maintenance

[58]. The NWC master plan specifically outlines the goal of a net-zero energy district, prioritizing technical and behavioral strategies to increase efficiency and using on-site renewable energy sources [59]. The NWC features key renewable energy opportunities including large rooftops available for solar PV, the potential for district-scale heat recovery from 2 m (72 in) diameter sewer pipe running above ground on site [59], and a potential biomass fuel source from the annual Western Stock Show.

This study is a net-zero site energy consumption analysis [27], meaning measured energy consumed and generated is limited to the geographical location of NWC. Net-zero energy district design principles are applied to the NWC campus, with an emphasis on the principles of maximizing solar potential and renewable thermal energy. The presence of a grid is assumed for electrical energy import and export [60], and the hourly load/generation energy balance is investigated in conjunction with on-site battery energy storage. Readily available tools and models are leveraged, including NREL's PVWatts [61] to estimate photovoltaic electricity potential, and EnergyPlus [41] with International Energy Conservation Code (IECC) 2015 building models [62] to forecast campus energy loads. In contrast to other studies, the economic analysis is limited to direct business costs, void of tax incentives on capital [63] and feed-in-tariffs on exported PV energy [32,64].

2.2 Method

The energy analysis consists of three steps: 1) estimating energy load, 2) assessing available renewable energy and quantifying its generation capacity, and 3) performing a net-zero energy and economic analysis of the energy scenarios.

2.2.1 Energy Load

The NWC master plan outlines a mix of existing and new buildings in the final campus configuration [59]. Existing buildings that will remain include the Denver Coliseum, Hall of Education, Events Center, and a renovated Maintenance building. New buildings include the Colorado State

University Water Resources Center (CSU WRC), Animal Health building, Stock Show complex, Livestock Hall and Arena, and the Equestrian Arenas and Paddocks.

Defining the energy load of the campus begins with examining collected utility data for the facilities that will remain in place. Three years of utility data (2014-2016) are analyzed and averaged for each of the defined building complexes. Electricity consumption is billed in kWh and natural gas consumption in therms. For clarity of reporting, total energy load is converted and summed in units of Mega-Joules (MJ) but distinguished between electricity and natural gas energy load types.

For future buildings, detailed models developed for the International Energy Conservation Code (IECC) [62,65] are used to estimate load on a per-square-meter of building basis. In terms of climate, Denver is located in Zone 5B described as “Cold, Dry”. The representative city of this climate is Boise, Idaho [66]. Of the various defined IECC commercial building types, “secondary school” was selected for the CSU WRC building, “outpatient healthcare” for the Animal Health Building, and “warehouse” for the Stock Show, Livestock, and Equestrian building complexes.

The IECC building models are run in the EnergyPlus [41] program with Denver TMY3 (Typical Meteorological Year) data to generate an hourly energy usage profile. Area-weighted IECC secondary school and outpatient healthcare models are applied directly to the CSU WRC and Animal Health buildings. A slight modification is made to the IECC warehouse type building to better correlate with the current NWC energy usage profile (see Figure 2-14). While maintaining the annual EUI, the hourly weighting is shifted to heavier use in January and February based on NWC historical energy usage data. This usage profile is reflective of the timing of the annual National Western Stock Show.

One of the goals of the NWC rejuvenation project is to increase show and event activities throughout the year. To that end, a projected campus load scenario called “2x Summer” is modeled where daytime energy usage from May 15 to August 15 is multiplied by a factor of two. This modification is intended to capture the energy impact of additional summer event activities at the site.

2.2.2 Renewable Energy Generation

Following the guidelines of the Net-Zero Energy Building (NZEB) classification system [26], design priority is given to local in-building and on-site options over off-site and purchased Renewable Energy Credits (RECs). To that end, the focus of this study is limited to on-site renewable energy resources. A preliminary high-level renewable energy feasibility assessment of the NWC campus concluded that solar PV, heat pump, and biomass are applicable on-site renewable energy sources (see Table 2-3).

2.2.2.1 PhotoVoltaic Electricity

Colorado is a state with good solar resources and Denver (1800 kWh/m^2 annual horizontal solar irradiation [61]) is on the edge of the southwestern region of the country where photovoltaic electricity is considered the most affordable [63]. The PV performance analysis begins with examining each building within the layout of the NWC campus [59]. Available roof areas are determined for both existing and future buildings, including whether the roof is flat or pitched. For flat roots, PV panels are positioned facing south and tilted up 40° from the horizontal [67] position to maximize the total annual electricity energy generation. For pitched roofs, PV panels are mounted at a standard 7° tilt roof pitch, and oriented per roof segment with the azimuth directional angle measured from north [68].

Assuming a nominal PV panel power density of 175 W/m^2 [69], the capacity of the panel array is determined for each roof segment based on an area analysis and fed with tilt and azimuth orientation into the NREL PVWatts calculator [61]. The output of hourly kWh of electricity is calculated for each building and summed annually over the entire campus. The economic analysis assumes a 0.75% annual degradation in PV output for each installation. Capital and operating costs of $1850/kW and $15/kW-yr for PV panels were obtained from NREL commercial system cost estimates [63,70].

2.2.2.2 Combined Heat and Power

A unique feature of the NWC campus is the available biomass of animal bedding waste from the National Western Stock Show. A rough estimate of 1000 tons of available bedding is calculated based on stock yard pen areas [71] and the density of wheat straw [72]. Since the Stock Show is in January, the availability of the biomass coincides with the greatest need for thermal energy.

The renewable energy potential of the biomass is calculated based on the performance of Biomax Combined Heat and Power (CHP) systems [73]. The Biomax systems are built from a nominal gasification module which can generate 155 kW of net electricity plus an equal amount of heating energy. The baseline system is a coupled 155 kW syngas engine, while a larger system comprised of a more efficient 710 kW engine is coupled with four gasification modules which allows output to be throttled in increments of 25%. Capital investment costs of $6000 to $8000/kW for installation of the CHP systems were estimated from conversation with Biomax [74], and $100/kW-yr operating costs are estimated from the NREL renewable energy costs overview [70].

2.2.2.3 Heat Pump

Heat pump technology is included as a renewable energy generation resource, even though it does not generate energy to offset load as the PV and CHP technologies do. Instead, it reduces the campus gas and total energy loads. A heat pump requires a thermal sink from which to exchange heat. Most commonly, the source is the ground, leading to the term Ground-Source Heat Pump (GSHP). Given the size of the campus, the NWC has more than adequate ground space to meet heat pump needs. However, the NWC site also features large 2 m (72 in) diameter above-ground sewer pipes to support wastewater heat exchange as a thermal energy source for the campus.

This work considers both opportunities by assuming that the heat pump energy performance is similar for GSHP or wastewater energy exchange. To quantify the energy load reduction, individual building heating and cooling energy loads are back-calculated using the 80% natural gas heating efficiency and 3.4 Coefficient of Performance (COP) cooling metrics of the IECC building models [65]. The heat pump performance is modeled with a COP of 2.9 and 4.5 in heating and cooling modes, respectively, reflecting a recent GSHP study done for Colorado State University's Moby Arena (see Table 2-7 and Table 2-8). The same study yielded heat pump renewable energy capital and operating costs of $600/kW and $1/kW-yr are calculated as increases over a conventional heating and cooling approach. The main cost difference is the in-ground heat exchanger (i.e. "bore-field"). An estimate of the cost of wastewater heat exchangers [75] yielded numbers similar to the bore-field cost (in $/kW), such that the general heat pump costs of this study are applicable for both thermal sources. Due to the differences in operating temperatures and the building infrastructure to support them, a given energy scenario may leverage CHP or HP technologies, but not both.

2.2.2.4 Energy Storage

Given the available wastewater and ground thermal resources, energy storage in this analysis is limited to lithium-ion battery electrical energy storage. The capital cost of battery storage is assumed to be $250/kWh, reported as a mid-range cost estimate in 2018 dollars for projected 2025 costs [76]. This future cost was selected since the electrical storage is implemented beginning in Phase 4 of the campus development, six years into the future (see Figure 2-16). Battery energy level and charging/discharging is analyzed on an hour-by-hour basis in the load/generation energy balance method. The difference with storage is that energy import/export priority is given to the battery first, and second to the grid. A 90% round-trip energy efficiency was assumed for the storage analysis based on the performance of commercially available batteries [77] coupled with a low energy-averaged discharge:capacity rate (i.e. battery "C rate") [78] and recognizing that inverter losses are included in the PV generation model [79].

2.2.3 Load/Generation Balance

The campus energy profile is analyzed on an hour-by-hour basis using modeled load and generation data for each phase of the NWC development. Mismatch between load and generation is analyzed separately for each energy carrier (electricity and natural gas) [80]. If the campus electricity power demand exceeds the renewable electric generation for a given hour, then there is a net electrical load, and energy must be imported from the grid. Conversely, if campus renewable electric generation exceeds the electrical power demand, then there is a net generation, and excess electricity is exported to the grid. For natural gas, when heating energy demand exceeds the renewable heat energy generation, natural gas energy is imported from the grid. There is no export of heat energy in this analysis since CHP operation is governed by heat energy demand. A technical-logical schematic of the movements of energy resources, electricity, and heat is shown in Figure 2-1. The general technologies considered are presented with electric and thermal distribution systems needed to exchange energy between buildings.

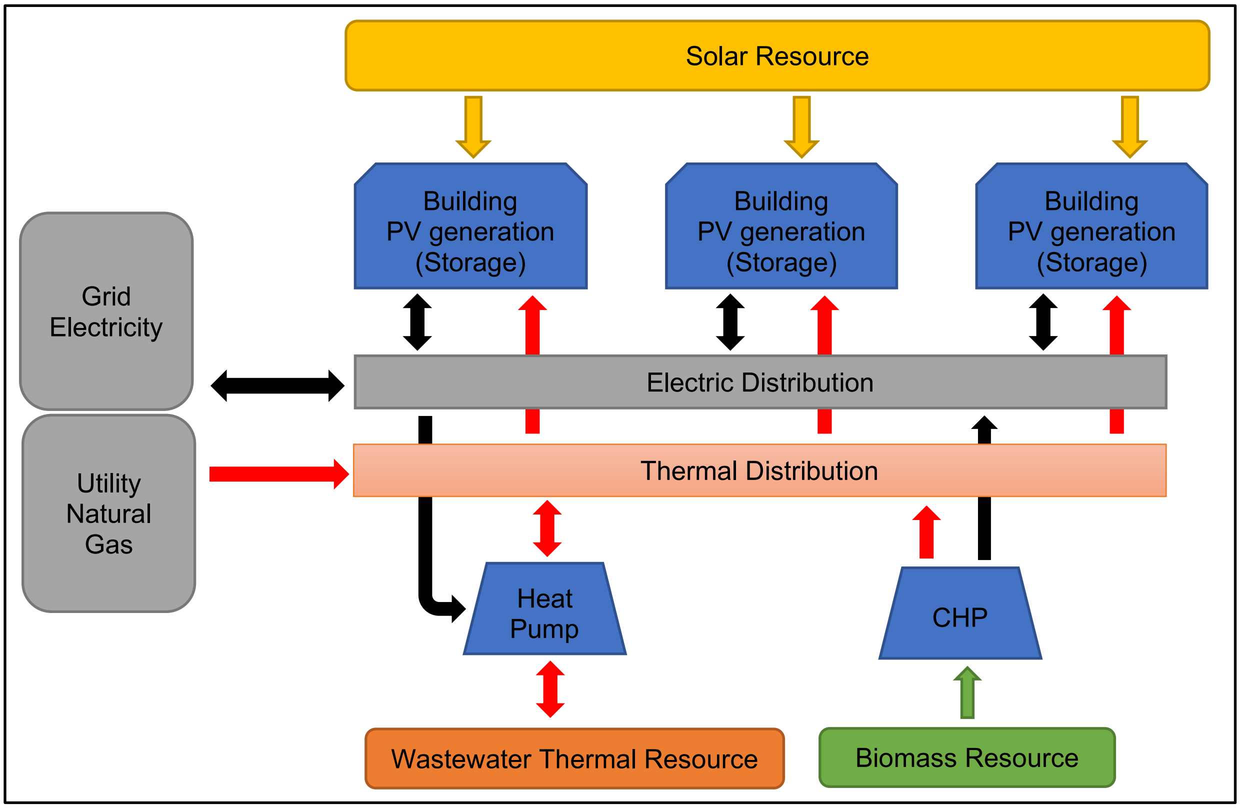


Figure 2-1. Technical-logical schematic for the load/generation analysis. Arrows indicate direction of (or bi-directional) flow of energy resources as well as electricity (black) and heat (red). The analysis assumes the presence of electric and thermal distribution systems to distribute electricity to and from buildings as well as distribute heat to and from the wastewater thermal resource via the heat pump. Electricity flow with the grid is bi-directional (can be exported), but useful heat energy cannot be exported from the campus.

2.2.4 Energy & Economic Analysis

Energy and economic analyses are conducted over a 30-year period, in line with NREL's Annual Technology Baseline's (ATB) capital recovery period and PV technology lifetime [81]. The first nine years contain five phases of new buildings (Stock Yards, CSU WRC, Animal Health, Livestock, Equestrian), such that year 10 is the first "steady state" year in terms of energy load and generation (see Figure 2-16). The hourly summed annual energy balance is analyzed for each phase and rolled into the analysis. For this mismatch between load and generation, the analysis assumes an electricity buy:sell ratio of 3 to 1 for energy exported to the grid. Economically, this means that three kWh of electricity must be sold back to the grid to offset the cost of one kWh purchased (imported).

Capital and operational costs are combined with the modeled energy balance of the system and characterized temporally to calculate LCOE on based on a 30-year discounted cash flow rate of return. Key economic parameter assumptions include loan assumptions, internal rate of return (IRR), depreciation, and taxation [82]. The loan terms were assumed to be 40% equity of the total capital with 8% interest over a 10-year term. Loan interest payments are counted as an operating expense. Depreciation is modeled with a 7-yr Modified Accelerated Cost Recovery System (MACRS) and impacts the taxes paid with a 35% assumed tax rate. An IRR of 5% is assumed, based on ATB's nominal weighted average cost of capital rate for commercial PV in recent years [83,84].

2.2.5 Model Sensitivity

A sensitivity analysis of the LCOE model is conducted for the scenarios achieving net-zero energy status. The analysis is conducted by calculating the resultant change in LCOE for a 10% positive and negative change in each of the eleven model parameters. A least squares linear model fit is run to compare the effects of the various model parameters based on a calculated t-ratio for each model parameter. A critical t-ratio is defined based on ten degrees of freedom for eleven parameters, and a

95% confidence interval. The effect of a model parameter is considered "significant" if it exceeds this defined critical t-value.

2.3 Results & Discussion

Energy analysis results include spatial and temporal characteristics of the load and generation of the campus. A load/generation balance is conducted on six defined scenarios to determine which ones meet the net-zero energy target on an annual basis. The LCOE is calculated with the corresponding technology solutions compared for scenarios successfully achieving net-zero energy. Sensitivity analysis is used to identify model parameters that have a significant impact on the LCOE. Energy analysis is done with and without energy storage with the results showing while net-zero energy is achievable, the economic feasibility is dependent on the buy:sell price relationship with the electric grid.

2.3.1 Campus Energy Load

Campus energy load is calculated as a total energy sum of electric and natural gas. The Normal and 2x Summer load profiles are coupled with and without Heat Pump (HP) technology to create four unique load scenarios deemed Normal, Normal HP, 2x Summer, and 2x Summer HP. Figure 2-2 graphically displays the four scenarios with color differentiated electric and natural gas consumption.

Implementing heat pump technology has two significant impacts on the load. First, the relative portion of energy load is shifted more heavily toward electric over natural gas. Campus wide, the HP electric:natural gas ratio shifts from 77:23% to 89:11% for the Normal load profile (see Table 2-4). The second significant load impact is a 10% reduction in total energy load, most visible in January and February. Heat pumps actually increase electric load, but since the heating COP is greater than one, the total energy load of the campus is reduced (i.e. "site"). It is recognized that electricity is a more refined energy source than natural gas and must be created from another fuel (i.e. "source"). However, even when a site/source conversion of 3.5 [85] is applied, the heat pump maintains a source energy reduction in addition to the more obvious site energy benefit.

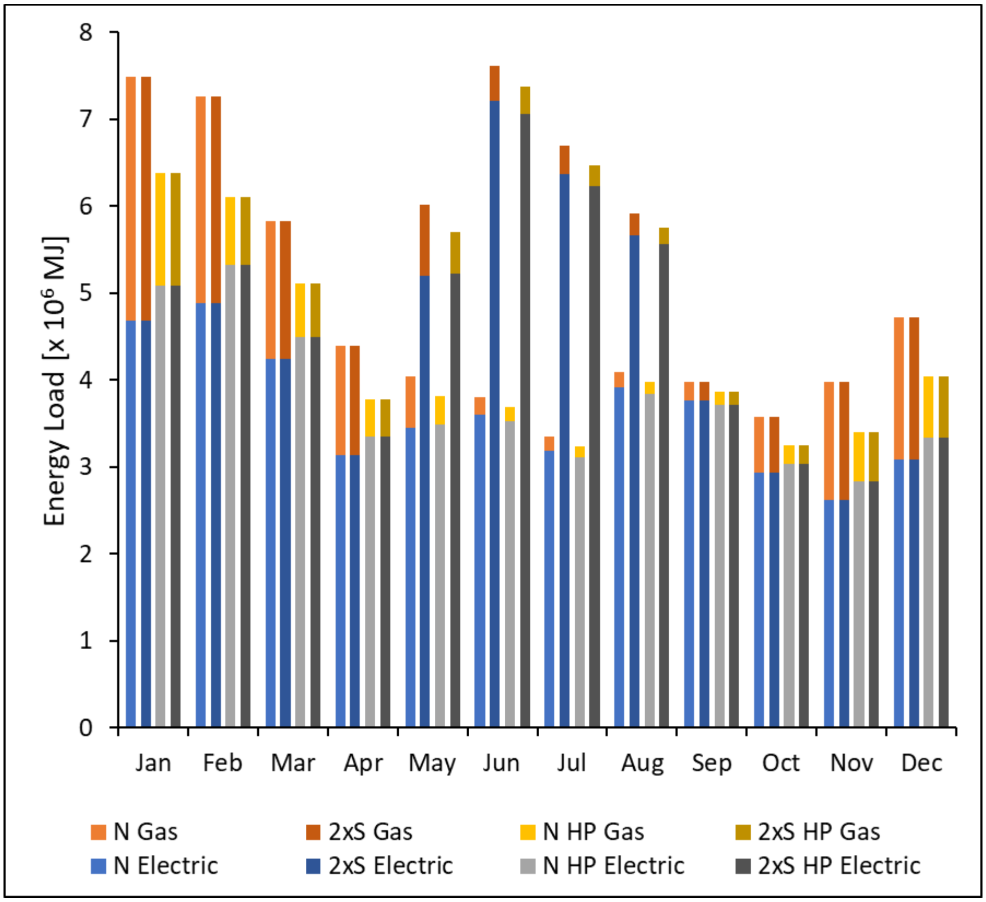


Figure 2-2. NWC Normal (N) and 2x Summer (2xS) monthly energy load profiles. The 2xS profile doubles the daytime load from May 15 to August 15, resulting in a 19% annual load increase. The 2xS June load also exceeds the normal peak load in January. Implementing Heat Pump (HP) technology lowers the annual load by 10% in both Normal and 2xS load scenarios, with the most significant impact in January and February.

The 2x Summer profile creates a heavy summer electric load, such that the June energy load exceeds the normal January peak. The NWC campus is home to the stock show in January and thus has a dramatic load in the winter during this event. The 2x summer load is intended to represent increased load of the campus due to new events scheduled. The 2x Summer load profile has the highest total energy load, 19% higher than Normal. The minimum annual load profile is the Normal HP, which is 90% of Normal. These shifts in campus energy loads will significantly impact the load/generation balance and the technological solutions that can meet net zero energy.

The NWC load is analyzed in terms of its building-to-building distribution based on both area and energy (see Figure 2-15). The CSU WRC and Animal Health buildings represent only 12% of the campus building area but comprise over 27% of the total energy load. Conversely, the livestock and equestrian building complexes represent 45% of the building area, but only 25% of the energy load. Since the PV generation potential is proportional to building area, the livestock and equestrian complexes are expected to generate a surplus of energy relative to their individual building loads that could offset deficits from other buildings. This is a benefit of conducting a campus wide analysis and implementation of a district solution in terms of energy.

The difference in distribution between building area and energy is reflective of the range of Energy Use Intensity (EUI) for the buildings across campus (see Table 2-5). The existing Events Center, Hall of Education, and Coliseum range from 286 to 508 (25 to 45) MJ/m^2-yr (kBTU/ft^2-yr). The Stock Show, Livestock, and Equestrian complexes are the lowest at 183 (16) MJ/m^2-yr (kBTU/ft^2-yr) compared to a campus high of 1180 (104) MJ/m^2-yr (kBTU/ft^2-yr) for the Animal Health building. It is noted that the assumed EUI of 183 (16) MJ/m^2-yr (kBTU/ft^2-yr) is lower than all existing NWC building structures. However, this reduction is in agreement with historical IECC models from pre-1980 to 2015 [86,87] that reflect a greater than 50% EUI reduction largely attributed to more energy efficient building design practices. The campus-wide EUI ranges from 297 (26) MJ/m^2-yr (kBTU/ft^2-yr) in the Normal HP load scenario to 395 (35) MJ/m^2-yr (kBTU/ft^2-yr) for 2x Summer.

2.3.2 Campus Energy Generation

Since the scope of this work is limited to on-site technologies, energy generation on campus is from PV and CHP sources. The PV generation capacity of a building is proportional to building footprint, and as expected, the high EUI WRC and Animal Health buildings are unable to generate enough electricity to offset their direct needs (see supplemental information Table 2-6). However, the low EUI Stock Show, Livestock, and Equestrian complexes each generate two to three times the electricity that they need individually and can thus make up this shortfall in the district analysis.

With PV as the baseline for campus energy generation, CHP energy generation is added to total generation capacity to achieve a net-zero energy campus. Figure 2-3 presents month-to-month total energy generation (electric plus heat) for three energy generating scenarios: PV only, PV plus Base CHP, and PV plus Large CHP. Base CHP on/off operation is governed by the hourly demand for heat. The large CHP system is throttled in increments of 25% in proportion to the 2x Summer profile heat demand. The resulting base and large CHP duty factors are 72% and 55% of annual capacity, respectively. The NWC biomass assessment estimates there is enough fuel to power the base CHP system for the full year, but additional biomass must be supplied to support the larger CHP system generation. To qualify as an on-site renewable energy source, the waste stream must be generated and processed within the district [27]. The assumption is made that the source of this fuel would be the campus solid waste stream, including briquetted food scraps, cardboard, and plastics [73].

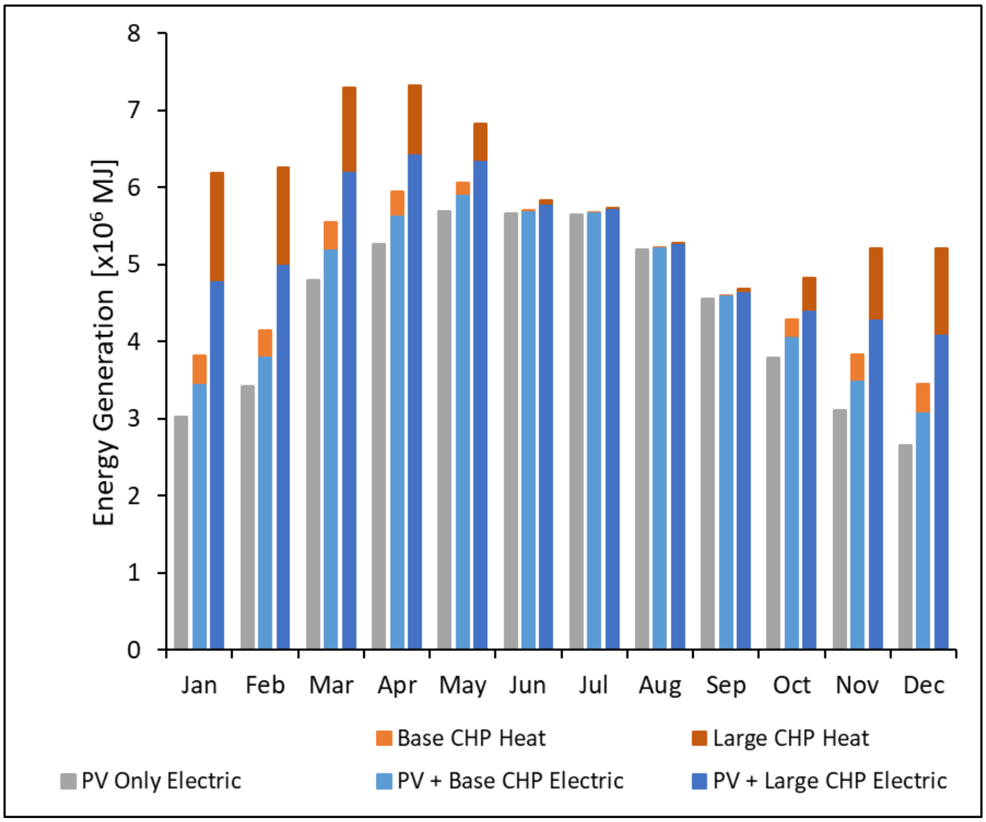


Figure 2-3. NWC Renewable Energy Generation by month. PV generation is the baseline for the campus and supplemented with either the base or large CHP technology. Heat energy is differentiated by color. CHP on/off duty operation is determined based on hourly heating load requirements. The resultant base CHP system operates at 72% of annual capacity. The large CHP is throttled in increments of 25% proportional to the 2x Summer heating load. The operational duty result is 55% of annual capacity.

Even though heat pump technology reduces energy load rather than actually generating energy, its energy impact on the NWC campus can still be compared to that of PV and CHP generation as shown in Table 2-1. The table data for PV and CHP is the annual sum of the monthly energy generation profiles of Figure 2-3. The reported HP energy generation is the resulting decrease in energy load, where a negative value (in parenthesis) indicates a load increase. The table shows that PV is the dominant source of energy generation. The HP energy impact is comparable to the generation capacity of the base CHP, while the large CHP generates more than three times the energy of the base CHP scenario.

Table 2-1. NWC annual energy generation capacity. Capacities are listed by renewable energy type and technology. Heat Pump (HP) is reported as a parenthesized negative electric generation meaning that electric load increases, and a positive heat generation meaning natural gas load is reduced. Thus, the total energy generation reported in the table is the energy load reduction compared to a non-HP scenario.

	PV	HP		CHP	
		Normal	2x Summer	Base	Large
Capacity [kW]	10200	3600		155	710
Electric Generation [x10^6 MJ]	53	(1.6)	(1.5)	2.8	9.9
Heat Generation [x10^6 MJ]	-	7.5	7.7	2.7	7.9
Total Energy Generation [x10^6 MJ]	53	5.9	6.2	5.5	18

2.3.3 Energy Storage and Balance

A net-zero energy analysis is conducted on a total annual energy basis. The Normal and 2x Summer load profiles are matched with PV, Heat Pump, and CHP renewable energy generation to create six unique energy load/generation scenarios: Normal PV only, Normal HP, Normal CHP, 2x Summer PV only, 2x Summer HP, and 2x Summer CHP, where the HP and CHP scenarios also include PV. Table 2-2 summarizes the annual net energy for each of the six scenarios, separating load and generation into electric and natural gas (heat) and summing the total annual energy. PV alone is insufficient to achieve a net-zero energy campus. However, combining PV with either HP or CHP technologies does enable three net-zero energy scenarios: Normal HP, Normal CHP, and 2x Summer CHP. All of these achieve similar levels of net-zero energy status as indicated in Table 2-2 where the total generation/load ratio exceeds 100%.

Table 2-2. NWC annual energy load and generation. Renewable energy scenarios incorporate PhotoVoltaic (PV), Heat Pump (HP), and Combined Heat and Power (CHP) technologies. Load and generation are listed as electric and natural gas (heat) in addition to total. Three of the six scenarios achieve net-zero energy status as indicated by the parenthesized negative annual net-energy and a total generation/load ratio greater than 100%. Net-zero energy is achieved through producing an excess of electricity to offset net natural gas load.

		PV Only		PV/HP		PV/CHP	
	Load Profile	Normal	2x Summer	Normal	2x Summer	Normal	2x Summer
Annual Load [x10^6 MJ]	Electric	44	54	45	55	44	54
	Natural Gas	13	14	5.5	6.0	13	14
	Total	57	67	51	61	57	67
Annual Generation [x10^6 MJ]	Electric	53	53	53	53	56	63
	Heat	-	-	-	-	2.7	7.9
	Total	53	53	53	53	58	71
Annual Net-Energy [x10^6 MJ]	Electric	(9.3)	0.9	(7.7)	2.4	(12)	(9.0)
	Natural Gas	13	14	5.5	6.0	10	5.7
	Total	3.7	15	(2.2)	8.4	(1.8)	(3.2)
Total Generation/Load Ratio		94%	78%	104%	86%	103%	105%

For the Normal campus energy load profile, PV paired with HP or CHP is able to achieve net-zero energy status. The 10% reduction in energy load enabled by HP technology brings the total energy load below the 53 × 10^6 MJ estimated generation capacity of the campus-wide PV such that the PV generation is now 104% of the load. The reduced natural gas load enabled by the HP technology is offset with excess generated PV electricity to achieve net-zero energy. With the base CHP energy generation, the PV plus CHP generated energy is 103% of the campus energy load due to additional CHP generated energy. In this case, the net natural gas load is reduced by the CHP generated heat, and the combination of excess PV and CHP generated electricity exceeds the net natural gas load.

For the 2x Summer campus energy load, the only renewable energy technology combination that can achieve net-zero energy status is PV plus CHP. The increased electric load of 2x Summer scenarios eliminates the excess PV electric generation seen in the Normal load scenarios such that the 2x PV only and 2x Summer HP scenarios are not able to achieve net-zero energy. To offset the 19% 2x Summer load increase, the large CHP capacity is required. As evident in Figure 2-3, the large CHP operational duty is limited from June through September when heat demand is low, but then significantly increased all other months. The CHP is run at the highest throttle to meet the hourly heating load, with the rationale to maximize the return-on-investment for the CHP capital expenses. The resulting annual generation/load ratio is 105% meaning that annual operational duty could be reduced and still maintain net-zero energy status.

Combining the campus load profiles of Figure 2-2 with the campus generation profiles of Figure 2-3, a net energy monthly load plot can be generated, as shown Figure 2-4. A negative net load indicates a surplus of generated electricity exported to the grid. Figure 2-4A shows the Normal PV only, HP, and CHP scenarios where the base CHP is applied. Figure 2-4B shows the 2x Summer PV only, HP, and CHP scenarios where the larger CHP system is applied. At the right of each plot, the annual sum in included. The monthly net load plot reveals significant energy generation shortfalls in December, January, and February for all scenarios. Comparing plots A and B of Figure 2-4, the 2x Summer increased load reverses the excess electric generation (negative net load) of June, July, and August such that there is now a small positive net load in those months. Also evident in Figure 2-4B is that the 2x Summer CHP operational duty could be reduced significantly in March and April and still achieve net-zero energy on an annual basis.

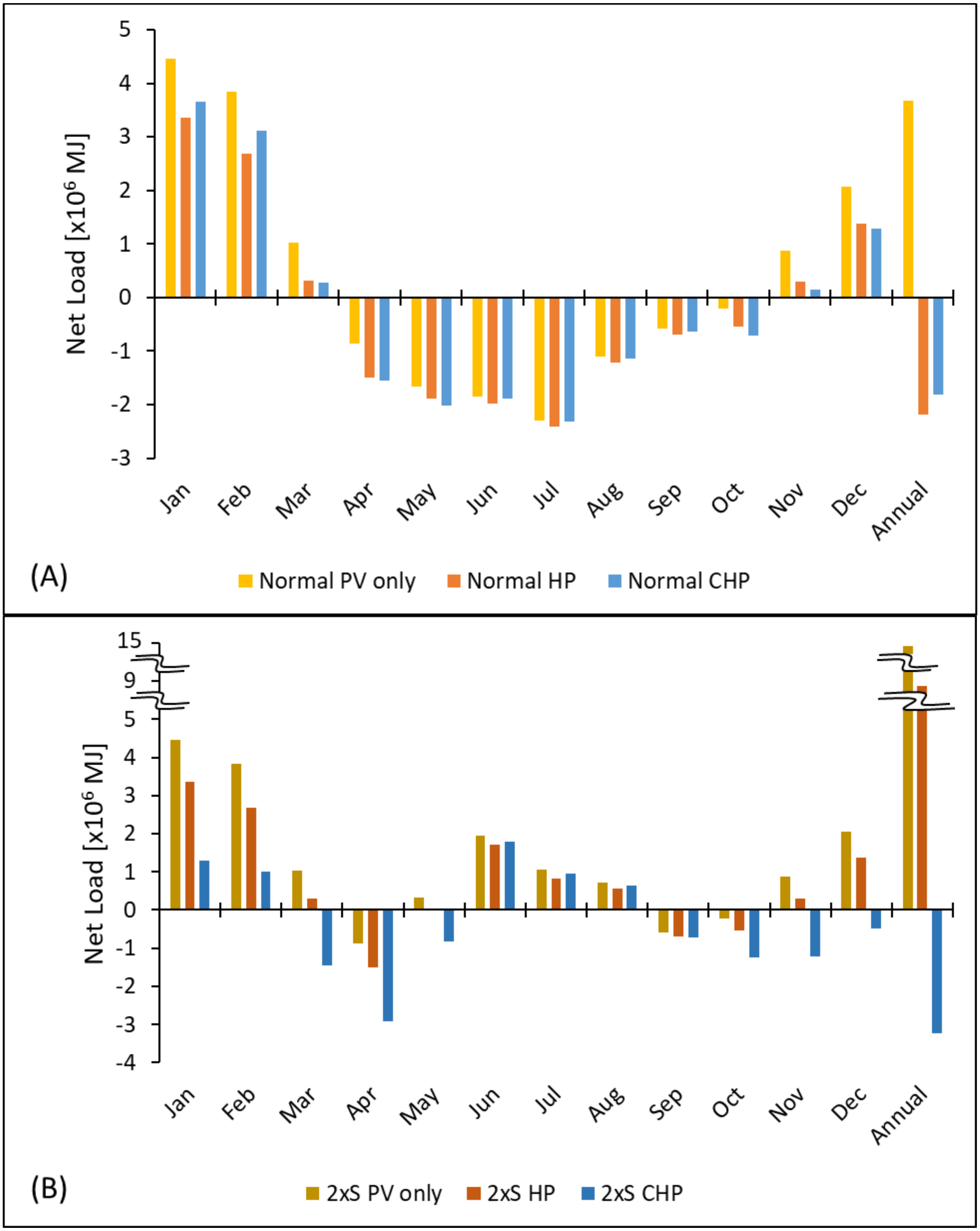


Figure 2-4. NWC monthly net load for each load/generation scenario. Negative load values indicate a surplus of energy generation. Plot A is Normal load with PV only, Heat Pump (HP), and base CHP generation scenarios. Plot B is 2x summer (2xS) load with PV only, HP, and large CHP generation scenarios. The net annual load is included at the far right, which is negative for the scenarios that achieve net-zero energy.

While achieving net-zero energy status as measured by annual net energy load is a beneficial design goal and accomplishment, it does not capture the full infrastructure impact of the campus energy design as energy flows to and from the grid. The three scenarios that achieve net-zero energy status do so by generating excess electricity. Furthermore, since most of the electricity is generated by PV, excess electricity will be generated during the day with a shortfall of electricity each night. Thus, electricity is exported to the grid during the day, and imported to meet load at night. From an energy accounting point of view, the grid acts as near-infinite capacity energy storage. While total energy load can be satisfied in this manner, the load/generation balance dynamics and economics of energy flow to and from the grid can benefit from local on-site storage in the form of Li-ion battery technology.

The impact of on-site storage is investigated by summing the flow of electricity on an hourly basis. Generated electricity distribution is prioritized to first offset load, second charge the battery, and third export to the grid if the battery is already fully charged. Electric load is first met by generated electricity, second by energy stored in the battery, and third by imported electricity from the grid. The analysis is repeated for various battery storage capacities to generate the plots shown in Figure 2-5. The separate plots of imported and exported electricity fraction are normalized by the total electric load and generation, respectively, for each energy scenario. The impact of storage on the cumulative load and generation is substantial, cutting the total grid dependence approximately in half.

Figure 2-5A plots the electric grid energy contribution (i.e. import), which is reduced from 30-45% to 15-25% with 10,000 kWh of storage. This amount of storage is determined later in the analysis to be a cost-optimal amount of storage representing approximately 30% of the annualized daily electric load. Even so, Figure 2-5 indicates that additional storage can reduce the grid energy import even more. This room for additional grid independence improvement is where collaborating agreements between NWC and the local utility could be used to increase the energy benefit by implementing storage capacities higher than merely the optimized campus cost capacity.

Figure 2-5B plots the generated electricity export fraction. Again, the impact of storage is significant, reducing the export fraction from 40-55% down to 20-33%. Unlike the import fraction, which falls to below 10% in some scenarios, the export fraction remains higher for most scenarios owing to the excess generated electricity used to achieve net-zero annual energy. Unfortunately, the lowest export fraction scenarios (2x Summer PV only and HP) do not achieve net-zero energy. Two other noteworthy items can also be seen on the figure. The first is that exported energy is reduced in all 2x Summer cases. Secondly, there is a minimum to which the PV export electricity fraction can be reduced with storage (~26% for Normal, ~12% for 2x Summer), at which point the storage has resolved the hourly and daily energy mismatch, leaving behind the seasonal mismatch of generated electricity.

In order to measure and compare the total infrastructure impact of the various NWC energy scenarios, a load match calculation is done on an hourly, per carrier basis [80]. In the NWC analysis, the carriers are natural gas and electricity. A positive hourly net energy load on each carrier is counted as positive net load, while negative net energy load is considered positive net generation. The hourly net generation is cumulatively summed and plotted versus the cumulatively summed hourly net load as shown for each scenario in Figure 2-6. The summed net load is energy (electric and natural gas) that must be imported from the grid and the summed net generation is excess electricity to be exported to the grid.

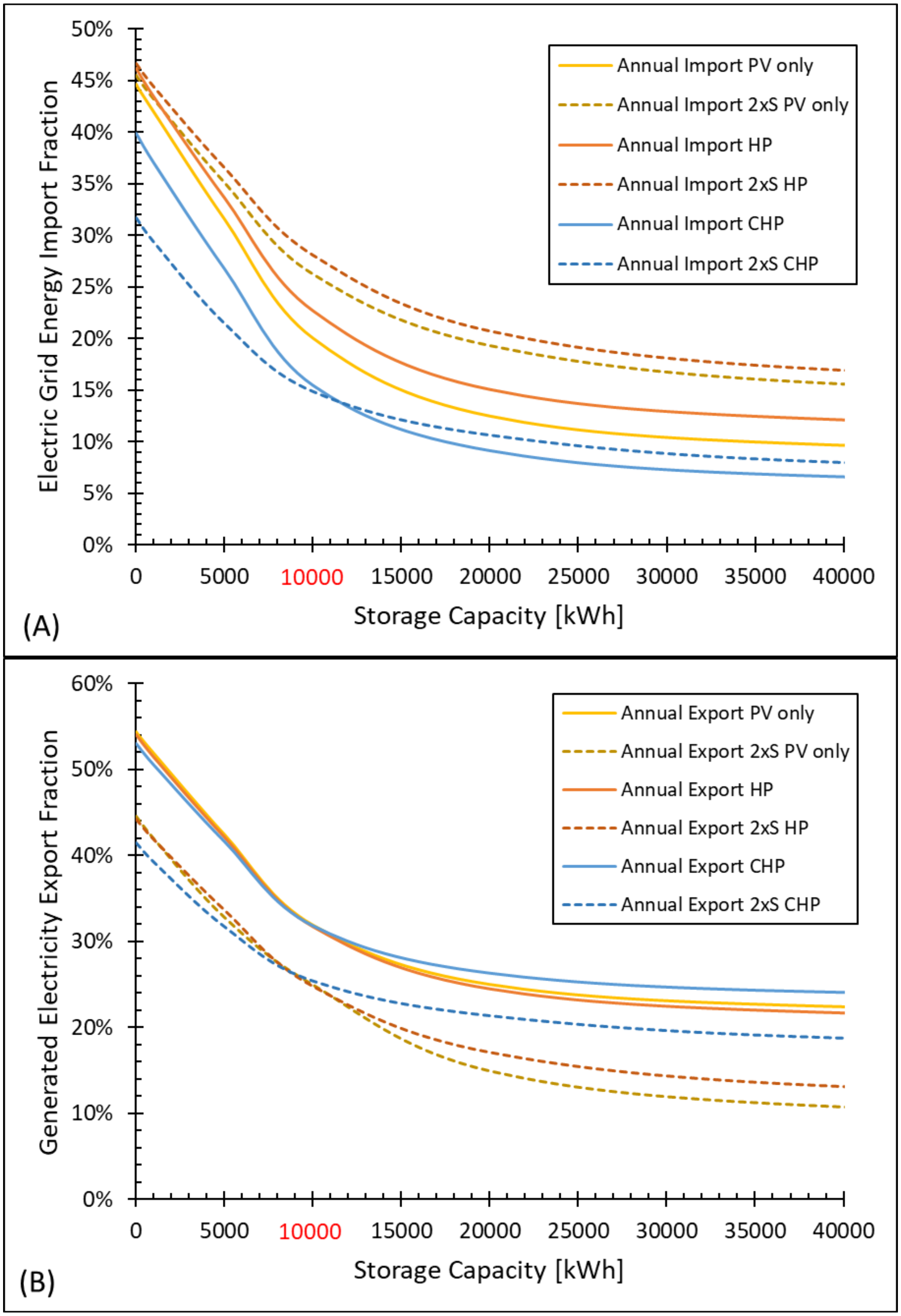
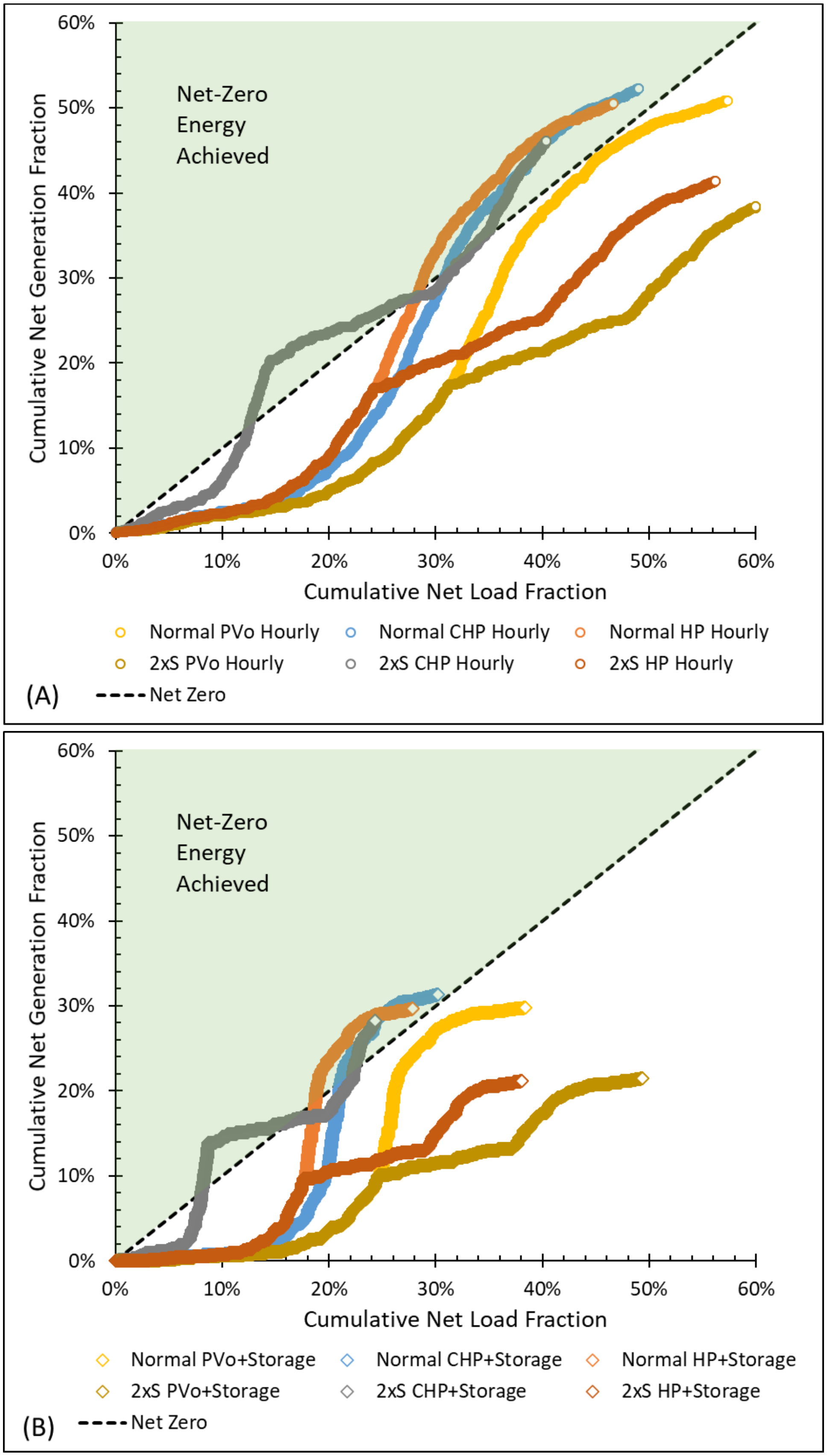


Figure 2-5. Effect of storage capacity. Plot A displays the imported grid electricity as a fraction of total electric load. The CHP scenarios import the smallest fraction of electricity while the 2x Summer (2xS) load scenarios generally increase the fraction of imported electricity. Plot B displays the exported electricity as fraction of total generation. The 2xS scenarios decrease export fraction most significantly due to alignment of peak summer load and peak PV generation. Increased storage reduces import and export fractions in all scenarios, with an effect that is greatest at smaller storage capacities. A levelized cost optimal 10,000 kWh of storage was assumed in the analysis.

There are two key results on display in Figure 2-6. The first key result is that if the trace of cumulative hourly summed energy ends above the dashed line, then net-zero energy status has been achieved on an annual basis. The further the end point is above this dashed line, the greater the net-zero energy margin. The second key result is the distance from the trace end point to the plot origin (0,0). This distance is a measure of impact on the energy infrastructure in terms of energy flow to and from the grid. Of the three energy scenarios that achieve net-zero energy status, the 2x Summer CHP is the closest to the origin and has the lowest net energy load sum. Further inspection of the 2x Summer CHP scenario (see Figure 2-4) indicates that throttling could be reduced in spring and fall months to reduce the net energy generation sum and infrastructure impact of electricity export to the grid further.

Figure 2-6A plots the six energy scenarios, showing that Normal HP, Normal CHP, and 2x Summer CHP all achieve net-zero energy. Figure 2-6B includes 10,000 kWh of battery storage, and the impact is dramatic. Note that the percentages of Figure 2-6 where electricity and natural gas are summed separately as distinct carriers, differs from Figure 2-5, which plots just electricity. For the net-zero energy scenarios with storage, the cumulative net load is reduced from 40-50% down to 20-30%, while the cumulative net generation is reduced from 45-55% down to 25-35%. In addition to being a cost optimal solution, the implementation of battery storage has a key energy infrastructure benefit of greatly reducing the quantity of energy imported from and exported to the grid.



Net-Zero
Energy
Achieved
Cumulative Net Generation Fraction
Cumulative Net Load Fraction
0%
10%
20%
30%
40%
50%
60%
Normal PVo Hourly
Normal CHP Hourly
Normal HP Hourly
2xS PVo Hourly
2xS CHP Hourly
2xS HP Hourly
(A)
Net Zero
Net-Zero
Energy
Achieved
Cumulative Net Generation Fraction
Cumulative Net Load Fraction
Normal PVo+Storage
Normal CHP+Storage
Normal HP+Storage
2xS PVo+Storage
2xS CHP+Storage
2xS HP+Storage
(B)
Net Zero

Figure 2-6. NWC cumulative net load/generation plots. Data of each scenario is summed hour-to-hour separately for each carrier (natural gas and electric) based on whether the net energy demand is positive (net load) or negative (net generation). Plot values are normalized as a fraction of total annual load and generation for PV only (PVo), PV/HP, and PV/CHP with both Normal and 2x Summer (2xS) loads. Plot A is the six baseline energy scenarios while plot B includes energy storage. The cumulative traces sum the dynamic energy flow to and from the grid and demonstrate a heavy dependence on the grid for all scenarios. A final position above the net-zero dashed line indicates net-zero energy status has been achieved on an annual basis. The farther the end point is above the dashed line, the greater the net-zero energy margin. The farther the final point from the plot origin (0,0), the greater the energy infrastructure dependence. Implementing 10,000 kWh of electrical storage (~ 30% of average daily load) cuts the grid interaction/dependence in half for both net generation exported energy and net load imported energy.

The fine detail results of Figure 2-5 and Figure 2-6 are dependent on the efficiency of the battery storage. A round trip of 90% was assumed in this analysis since it is possible to DC-couple the energy storage knowing that AC-DC-AC conversion power electronics losses are the largest contributor to storage losses [78,88] and inverter losses are already included in the PV generation data [79]. If the round-trip efficiency is lower, then the district energy import fraction (Figure 2-5A) and the cumulative net load fraction (Figure 2-6) will both increase as energy is lost due to storage inefficiency. These combined effects lower the net-zero energy margin as evident by the cumulative traces of Figure 6 ending closer to the net-zero energy boundary line. The net-zero energy impact is tempered by the fact that storage inefficiencies do not impact the generated energy that directly offsets district load. For the levelized cost results in the following section, the impact of these percentage energy losses is minor in comparison to the buy:sell ratio of 3 that economically incentivizes storage.

2.3.4 Levelized Cost of Energy

Up to this point, all energy analysis has been done on a built-out campus with full energy loads offset by full renewable energy generation capacity. However, the NWC rejuvenation is a multi-year phased process, so adding a temporal component to the analysis is important. To compare the energy scenarios capable of achieving net-zero energy status, a LCOE calculation is made based upon phased 30-year energy profiles and the economic parameter assumptions outlined in section 2.2.4. The first ten years of the analysis features five discrete steps of increasing annual energy load as new buildings are added (see Figure 2-16). The CHP technology is brought online in year 3 (phase 3). The Livestock and

Equestrian buildings are brought online in years 6 and 9 (phases 4 and 5), bringing with them a large PV generation capacity, such that net-zero energy status is achieved in year 10. Storage is added in two equal capacity halves in phases 4 and 5. LCOE is calculated as the energy cost to achieve a zero Net Present Value (NPV) for the capital and operating expenses distributed over the 30-year analysis.

The LCOE calculation enables investigation and economic optimization of model parameters and assumptions. Figure 2-7 presents the LCOE as a function of storage capacity. The nominal buy:sell ratio of 3 is plotted as well as much less favorable ratio of 100. Only the three net-zero energy achieving scenarios are included in the plot. A storage capacity of 10,000 kWh represents a near cost-optimal amount for all three energy scenarios and both buy:sell ratios. Storage has a greater benefit with a higher buy:sell ratio, while the 2x Summer CHP is least sensitive to storage owing to the better overall match between load and generation. Despite the energy benefit of increased storage capacity noted in Figure 2-5, optimization of LCOE keeps the storage quantity near the 10,000 kWh assumed in the analysis.

The cost-optimal amount of storage is impacted by the frequency of its use and the temporal resolution of the pricing structure. The optimal amount of storage would likely change if a more complicated time-of-use electricity pricing structure were implemented. At 30% of the annualized daily electric load, the 10,000 kWh storage fits the typical profile of PV electricity generated and stored during the day to be used that night. Figure 2-7 also shows that in most scenarios, doubling the storage to 20,000 kWh is still more cost effective than no storage at all. In this case, additional energy is being stored on very sunny days to be used for future cloudy ones. Because the frequency of these weather transitions is less than the daily diurnal cycle, the economic value of the storage is diminished. Finally, Figure 2-7 shows that the economic value of storage continues to decrease with increased storage capacity. While there remains energy benefit to storage on this scale, the low frequency of use cannot effectively make up the additional capital cost investment.

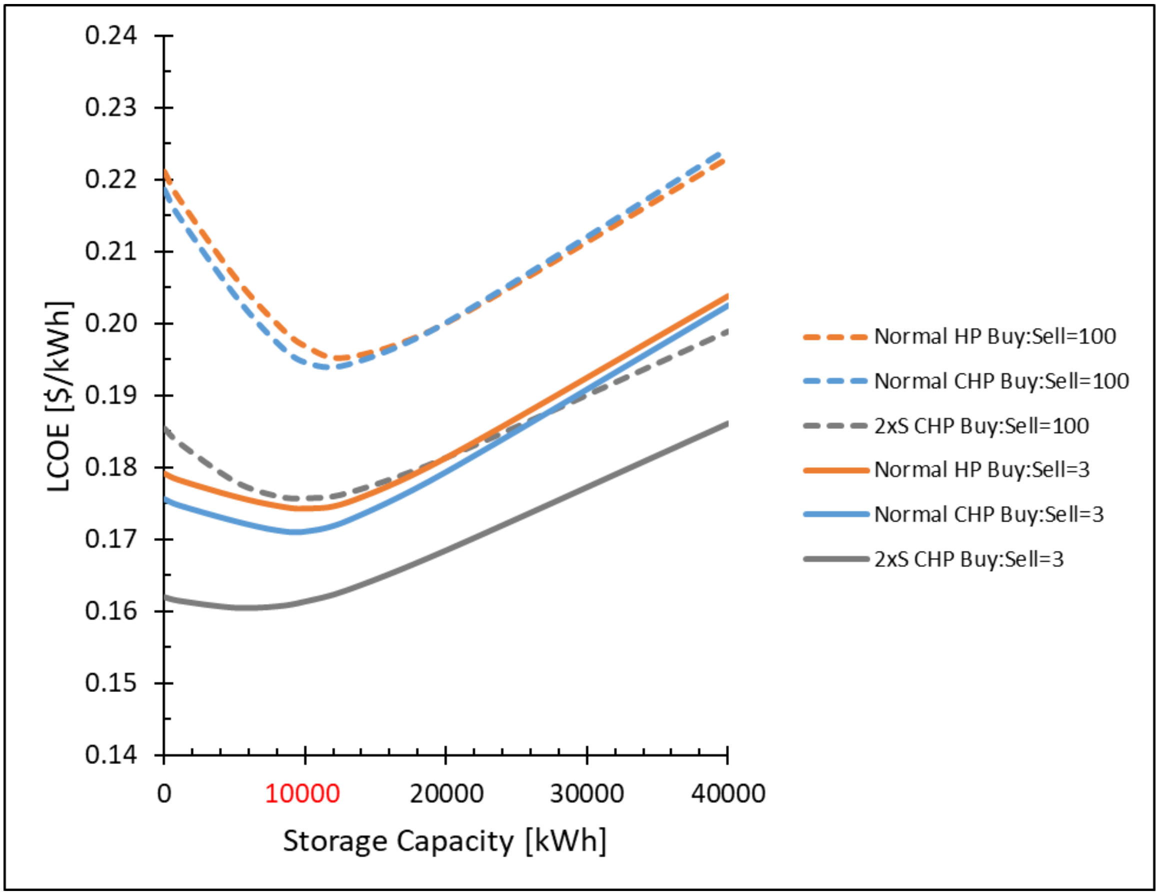


Figure 2-7. Levelized Cost of Electricity (LCOE) as a function of storage. Results are plotted for net-zero energy scenarios with buy:sell ratio traces of 3 and 100. For all scenarios and buy:sell ratios, the levelized cost optimized storage capacity is near 10,000 kWh (~30% of annualized daily electric load), which is the capacity assumed in the remainder of this analysis.

The economic value of storage is heavily influenced by the buy:sell ratio. With the assumed buy:sell ratio of 3, the value of exported electricity is only one-third the cost of imported electricity. However, if the same three kWh could instead be stored in a battery and later used to offset load rather than import energy, then they retain the same value as imported electricity, less the efficiency losses of storage. This energy retained value benefit increases and decreases in proportion to the buy:sell ratio. When the buy:sell ratio is one (net metering), then stored energy has no additional economic value at all.

Figure 2-8 investigates the impact of buy:sell ratio on LCOE for the net-zero energy scenarios with and without storage as a function of buy:sell ratio. At a buy:sell ratio of one (net metering), no storage achieves the lowest overall LCOE between $0.12 and $0.13/kWh. The minimum LCOE with storage is nearly $0.14/kWh at a buy:sell ratio of one. A cross-over in LCOE occurs between buy:sell ratios of 1 and 3, such that at higher buy:sell ratios, energy storage yields a lower LCOE. This difference levels off and is most pronounced at buy:sell ratios of 100 or higher. At this extreme, storage reduces the Normal HP and CHP LCOE from $0.22 to $0.19/kWh, and the 2x Summer CHP from $0.19 to $0.17/kWh. The buy:sell ratio of 3 assumed in this analysis was based on a comparison of retail and wholesale electricity prices [89,90].

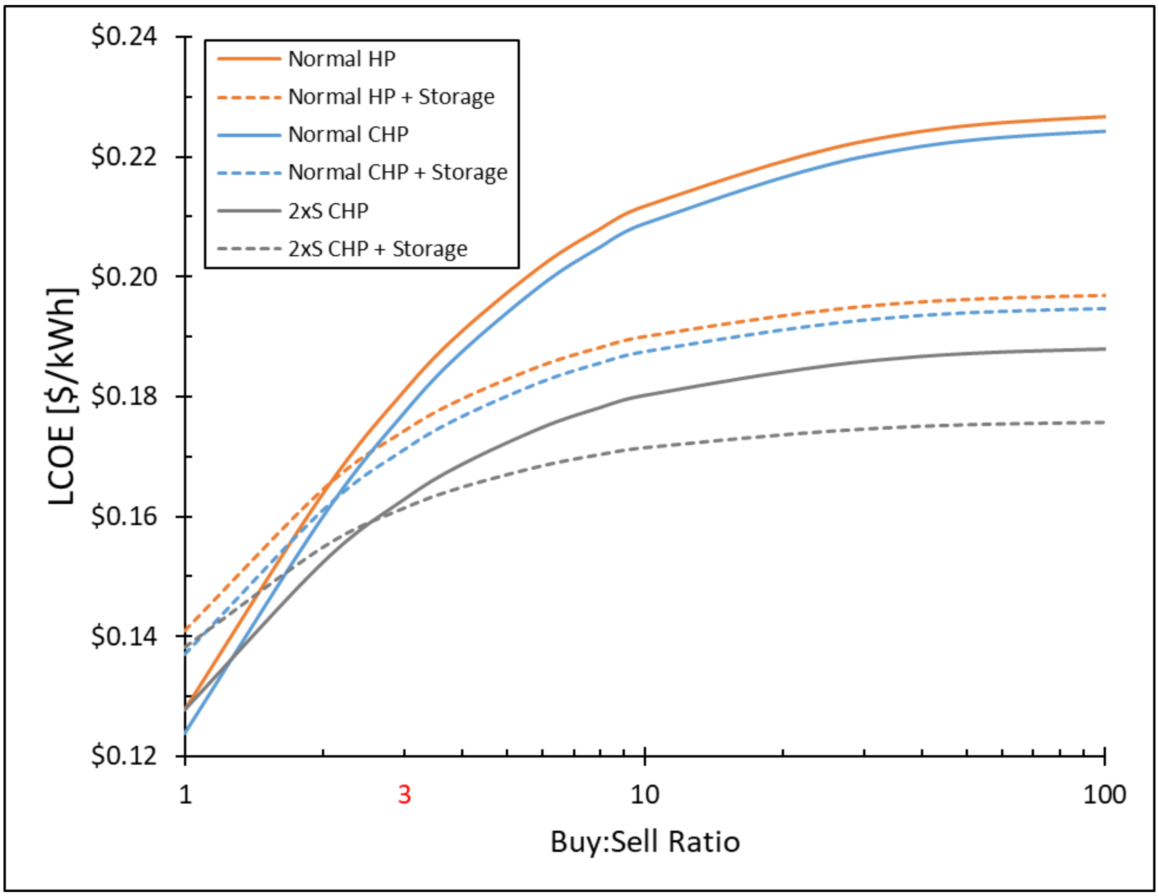


Figure 2-8. Levelized Cost of Electricity (LCOE) with and with without storage. Only net-zero energy scenarios are plotted. A buy:sell ratio of 1 is net metering where the results cluster with their minimum LCOE near $0.14/kWh and $0.13/kWh with and without storage, respectively. As the buy:sell ratio increases, scenarios with storage achieve a lower LCOE. The cross-over buy:sell ratio is between 1 and 2 for the normal load profiles, and just over 2 for the 2x Summer (2xS) CHP net-zero energy strategies. A nominal buy:sell ratio of 3 was assumed in this analysis based on a comparison of wholesale and retail electricity prices [89,90].

The impact of the buy:sell ratio on LCOE captures the importance of the grid for net-zero energy economic feasibility. This grid dependence can be further demonstrated by taking the energy analysis to an extreme and determine what it would take to achieve net-zero energy independent of the grid (micro-grid). From an energy point-of-view, the hourly energy balance (including storage) must always yield a zero or negative net load as there cannot be an energy shortfall. One way this can be done is to add enough storage to overcome the seasonal mismatch of PV electric generation. For NWC, this would require 1.36 million kWh of battery storage, a capital investment of $340 million, and a resulting LCOE of $1.77/kWh. In essence, this enlarged capacity is storing peak summer generated electricity to use in the winter where the generated electricity is less than the load. The annual frequency of storage use in this situation is very low, and results in an LCOE that is ten times higher than that achieved when connected to the grid.

A second method to achieve a micro-grid is to increase the PV generation capacity. The winter seasonal shortfall in electricity can be bet met with an additional 8500 kW of PV capacity, but storage must also be increased to 120,000 kWh (about three days of winter load) to meet all the energy load. The result is an additional $45 million in capital resulting in a LCOE of over $0.33/kWh. While this cost is much better than the storage-only micro-grid approach, the LCOE is twice that of the grid-dependent net-zero energy scenarios. Clearly, the grid is an important factor in the economic feasibility of net-zero energy districts.

The LCOE of the three net-zero energy scenarios is shown in Figure 2-9 subdivided into categories of capital expenditures (equipment and facilities), operating costs, and taxes; and further broken down to reflect the portion from each renewable energy source. The cost is reported per kWh of energy since this is a metric more intuitively understood and typically reported for PV energy generation. As a cost point reference on the plot is the average electricity from NWC utility bills of $0.105/kWh, in agreement with electricity prices reported by the U.S. Energy Information Administration [89]. Since the economic analysis is built on an IRR of 5%, comparing to these utility rates is not directly applicable, but they do represent an evaluative benchmark for the renewable energy technologies, nonetheless. Also included on the plot is the $0.33/kWh additional PV and storage micro-grid calculated result.

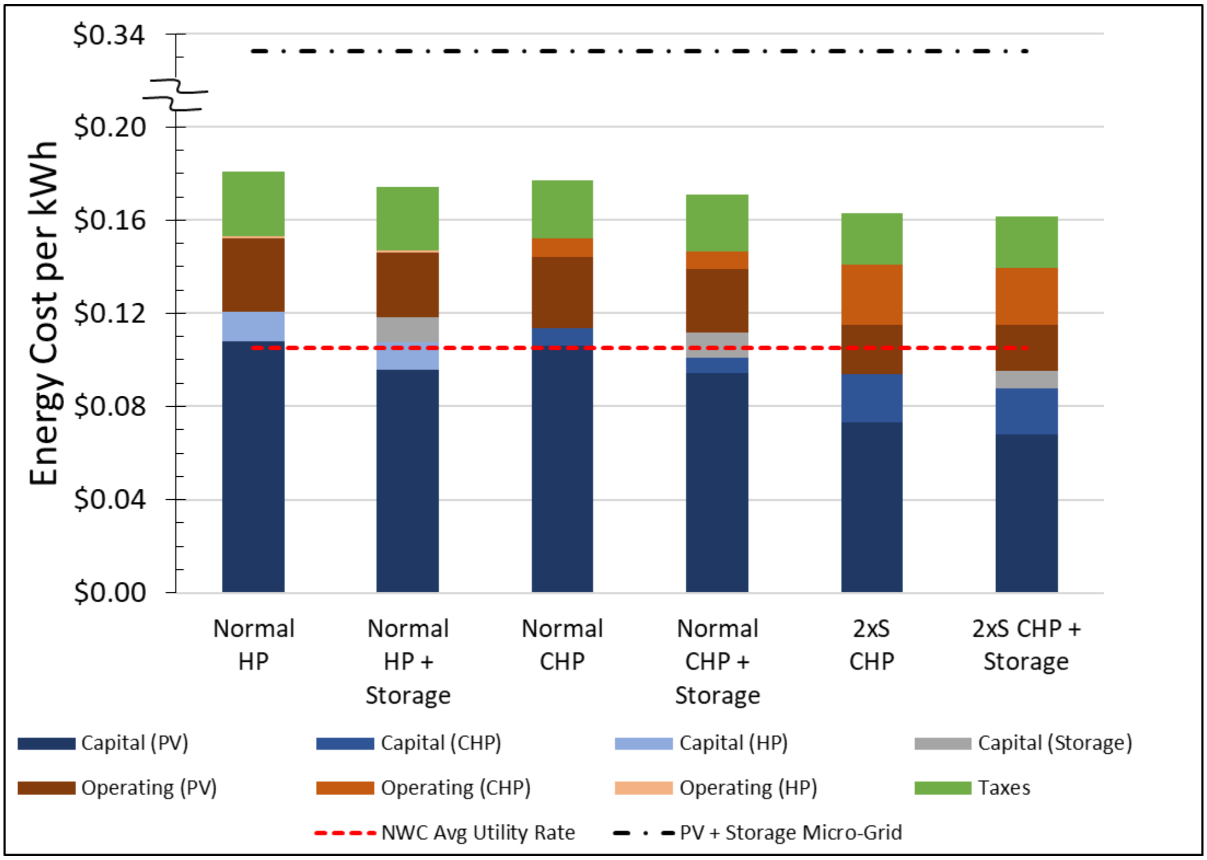


Figure 2-9. Net-zero energy Levelized Cost of Energy (LCOE) breakdown and comparison. CHP scenarios result in lower LCOE due to better winter (December, January, February) load matching and lower per energy generation capital cost. The 2x Summer (2xS) CHP is the lowest LCOE benefiting from better summer (June, July, August) load/generation matching. The impact of storage is minimal with the buy:sell ratio of 3 assumed in the analysis. The best net-zero energy LCOE is just above $0.16/kWh, which is considerably higher than the average retail electricity rate paid by NWC ($0.11/kWh), but much lower than the PV + storage micro-grid ($0.33/kWh), both of which are included on the plot for comparison.

The CHP energy scenarios achieve the lowest LCOE values in large part because of their no-cost waste stream sources, with modest fuel processing costs assumed in the operating expenses. It is possible that these CHP operating expenses could increase significantly based on the condition of the source fuel. The CHP LCOE is also lower due to its inherent combined electricity and heat energy benefit and the fact that its dispatchable output can be better matched to NWC's winter heavy energy load. Despite the lower operational duty of the large CHP, the 2x Summer CHP energy scenario results in the lowest LCOE due to a better match of increased summer load with summer peak PV energy generation. The LCOE was observed to be reduced in all 2x Summer scenarios for this same reason. The LCOE of all six scenarios is increased due to taxes, loan interest, buy:sell ratio, and the 9-year period over which the PV modules are installed.

Despite the heavy reliance on PV electricity to achieve net-zero energy, the LCOE results of this analysis are significantly higher than other published PV LCOE published values [63]. This is largely due to the exclusion of capital tax incentives, an IRR greater than historical inflation, and the buy:sell ratio. In addition to these differences in economic modeling, the NWC has less than optimal PV output due to campus building and roof orientations. A south facing (180° azimuth), 40° tilt PV system is expected to generate over 1600 kWh/kW per year, while the area-weighted average output of the NWC PV analysis is just over 1400 kWh/kW.

With the buy:sell ratio of 3, the Normal HP, Normal CHP, and 2x Summer energy scenarios all achieve a lower LCOE with the 10,000 kWh battery storage. The range of LCOE of all three is close, between \$0.16/kWh and just over \$0.17/kWh. As can be observed in Figure 2-9, these values are all significantly higher than NWC's retail rate of conventional grid electricity at less than \$0.11/kWh. However, these LCOE values are substantially lower than the best micro-grid scenario (\$0.33/kWh), which emphasizes the critical role played by the grid in the economic feasibility of net-zero energy districts. It is important to also acknowledge benefits not captured in this analysis such as CO_2 reduction, urban design, and quality of life, which all factor into NWC's sustainability objectives and its initiation of a net-zero energy goal. Indeed, factors like these are often leveraged in the creation of government capital investment tax incentives and feed-in-tariffs (buy:sell < 1) to make up the existing LCOE difference observed in this analysis.

The LCOE advantage of storage energy scenarios is also significant to the role of the grid in net-zero energy districts. Storage is a benefit to NWC in terms of LCOE, as well as to the grid in terms of dynamic flow and energy dependence. Storage has also been demonstrated to be important to grid stability in a sub-hourly power analysis [29]. The buy:sell ratio of this analysis is an initial quantification of the important relationship between the grid and the net-zero energy district. Design and development in concert with the local utility is one area emphasized in public-private partnerships of the ZEDA initiative. Indeed, future work on this front can explore the impacts and optimization of storage with time-variant electricity prices and other possible grid stability pricing and capital incentives. These are likely to play out somewhat differently for each net-zero energy district under consideration and thus it is important to partner and collaborate early in the district energy development.

2.3.5 Sensitivity Analysis

Sensitivity analysis results of the LCOE model for the three scenarios achieving net-zero energy status are shown in Figure 2-10. For the eleven model parameters (ten degrees of freedom) with a 0.05 significance level (95% confidence) on a two-tailed distribution, the critical t-value is 2.23 and marked as a dashed line in Figure 2-10.

As expected, energy output and capital costs have the highest impact, with the energy output being negative because an increase in energy output decreases the LCOE. Time value of money parameters (IRR and loan interest) also rank high on impacting results, while buy:sell ratio, tax rate, and operational cost are also statistically significant. Large changes in the assumed values of these parameters will significantly impact the LCOE results. The sensitivity analysis also indicates the operational cost impact is relatively more important in the CHP scenarios where operating costs per kW are much higher than PV or heat pump. The operating cost t ratio further increases for the larger 2x Summer CHP scenario. Thus, if fuel processing costs are significantly higher than currently estimated, the CHP technology will be less economically attractive. The loan term, PV annual degradation, and loan equity impacts all have statistically insignificant impacts on the LCOE results. Storage capacity appears as the least significant parameter because the 10,000 kWh capacity assumed is near the cost optimum value for all scenarios.

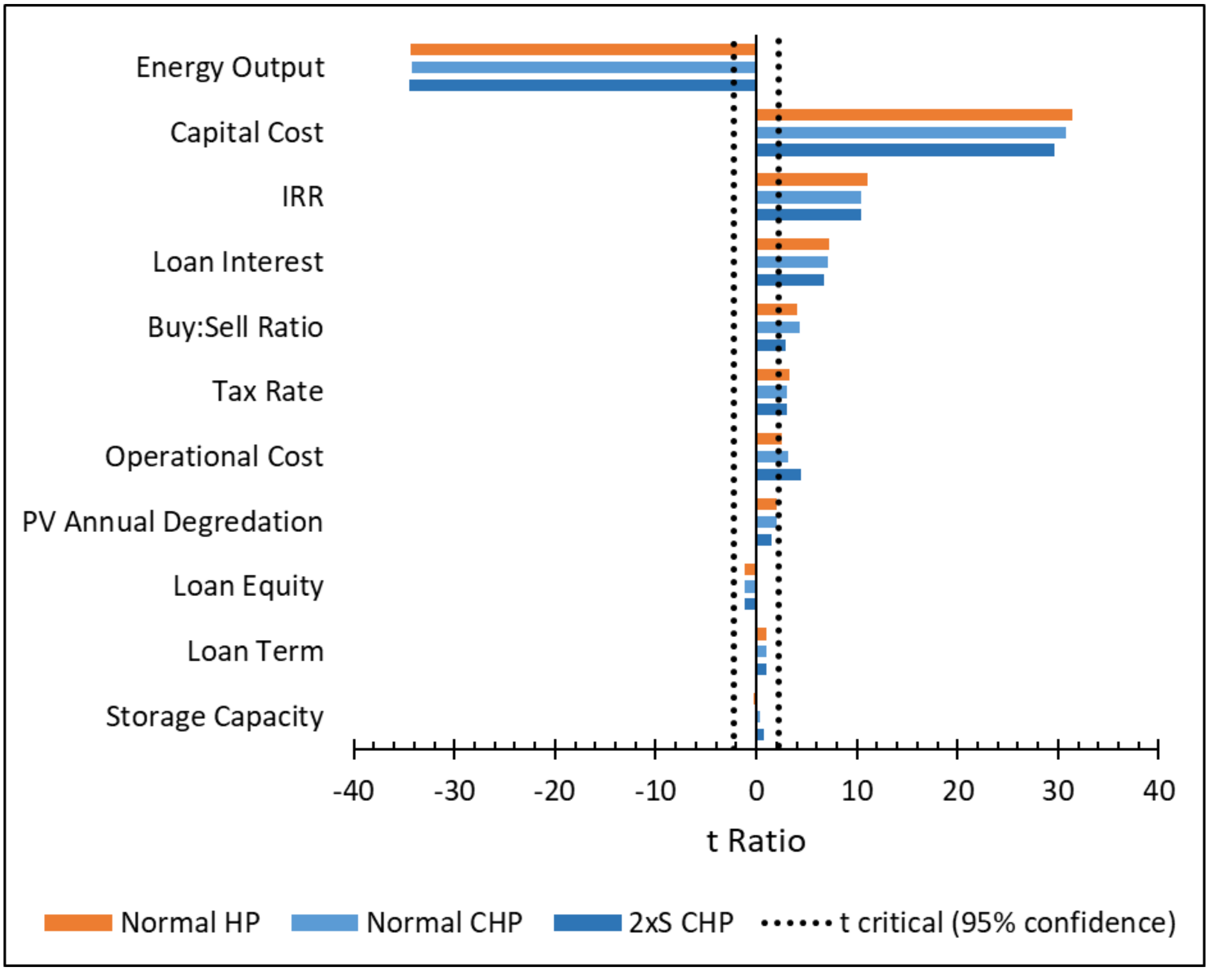


Figure 2-10. LCOE sensitivity analysis. Results are based on a ±10% change in each parameter. While energy output, capital cost, IRR, and loan interest are the most sensitive in effecting a change in LCOE; buy/sell ratio, tax rate, and operational cost are also statistically significant for all three net-zero energy scenarios. Storage capacity has the least significant impact on LCOE because a cost optimal amount of storage was used in the analysis.

2.4 Conclusions

An interesting opportunity for renewable energy penetration is the development of net-zero energy districts. The work leverages detailed building energy modeling coupled with energy generation modeling to evaluate not only the ability for different renewable energy system configurations to meet NWC's net-zero energy target, but also quantify the economic viability and their level of grid dependence. Results show that multiple combinations of PhotoVoltaic (PV), Heat Pump (HP), and Combined Heat and Power (CHP) technologies can achieve net-zero energy status with a LCOE in the range of $0.16 to $0.18/kWh with the assumed model parameters, and below $0.13/kWh with net metering. The large building area and low Energy Use Intensity (EUI) Livestock and Equestrian complexes offset the high EUI impact of the Water Resource Center (WRC) and Animal Health buildings; a benefit of broadening the net-zero energy analysis to the entire campus.

Heavy deployment of PV modules on existing and new buildings is the baseline strategy to achieve a net-zero energy campus. In addition to PV electricity, on-site biomass and thermal sources can be leveraged in CHP and HP technologies, respectively, creating alternative net-zero strategies that can meet the current thermal energy load, as well as load models for future increased summer events. CHP offers a cost advantage in terms of LCOE ($0.004/kWh less than HP) while the heat pump has a slightly more favorable net load/generation balance (47%/51%) than CHP (49%/52%). The heat pump approach also offers a sustainability advantage in lowering the total site energy load by 10% and maintaining an energy advantage from a source perspective.

The critical role played by the grid is quantified with a buy:sell energy pricing ratio, where net metering is equal to one and feed-in tariffs are less than one. A buy:sell ratio of 3 was assumed in the analysis, in which battery storage energy scenarios gain up to a $0.009/kWh LCOE advantage over scenarios without storage. Storage is also a benefit in terms of grid independence where the energy export and import ratios can be reduced from greater than 50% to less than 30%. This coupling between district energy cost advantage and reduced grid independence driven by the buy:sell ratio indicates that a collaborative partnership between the net-zero energy district and the local utility is key to the economic feasibility of the net-zero energy district.

This initial net-zero campus study sets the stage for future energy monitoring and net-zero energy studies as the NWC development advances. Energy models and strategies developed, employed, and validated at the NWC can be applied to buildings and campuses across the world in an effort to cultivate building and district design practices that benefit local, national, and global communities.

2.5 Future Work

Since the completion of this study, progress has been made at the NWC as part of the rejuvenation plan. Specifically, the Animal Health and Water Resource Center (WRC) buildings have become a reality in a new three-building complex known as CSU Spur [91]. The three buildings are called “Vida”, “Terra”, and “Hydro” where Vida is the manifestation of the Animal Health building, and Terra and Hydro are separate land and water focused buildings that grew out of the original WRC building concept. A decision has also been made to move forward with a centralized wastewater heating system advertised as the largest sewer heat recovery system in North America that is expected to source nearly 90% of the heating and cooling needs of the campus [92].

The future research opportunity thus comes in the form of validation opportunities for the models used in this study. The Animal Health and WRC complexes were the highest EUI buildings and together accounted for 27% of the entire campus load. Modeled as outpatient healthcare and secondary school IECC buildings [62] respectively, the opportunity exists to collect real usage data and compare the models selected to represent those facilities. Even though the wastewater heat recovery system has been selected as the main renewable heat source for the campus, the available animal bedding waste still presents a compelling opportunity to pilot a small-scale CHP system for thermal load not met by the wastewater heat recovery system. An important starting place for this work will be a thorough technical investigation of the failed Denver Zoo waste-to-energy project [93] to ensure feasibility of the NWC implementation. Finally, the planned wastewater heat recovery system presents a research opportunity to validate the energy savings predicted for the campus with such a heat pump system. In all these ways, the NWC net-zero district initiative presents opportunities to further develop sustainable energy practices within the local community.

2.6 Supplemental Information

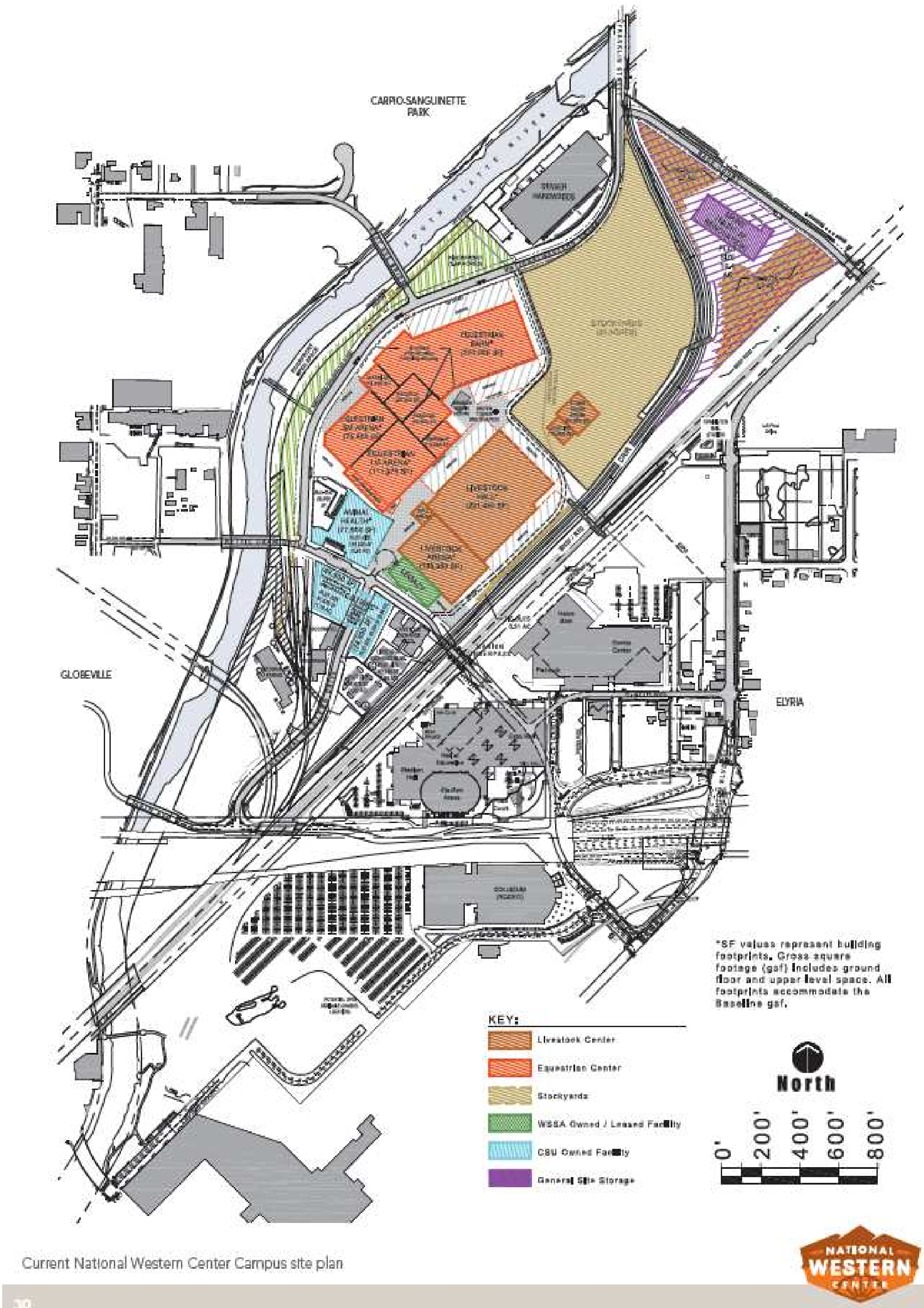


Figure 2-11. NWC Site Plan showing the geographical layout of the major building complexes. The orientation of each building coupled with architectural renderings of flat or sloped roofs was used to calculate the PV generation potential of each separate building complex. [59]

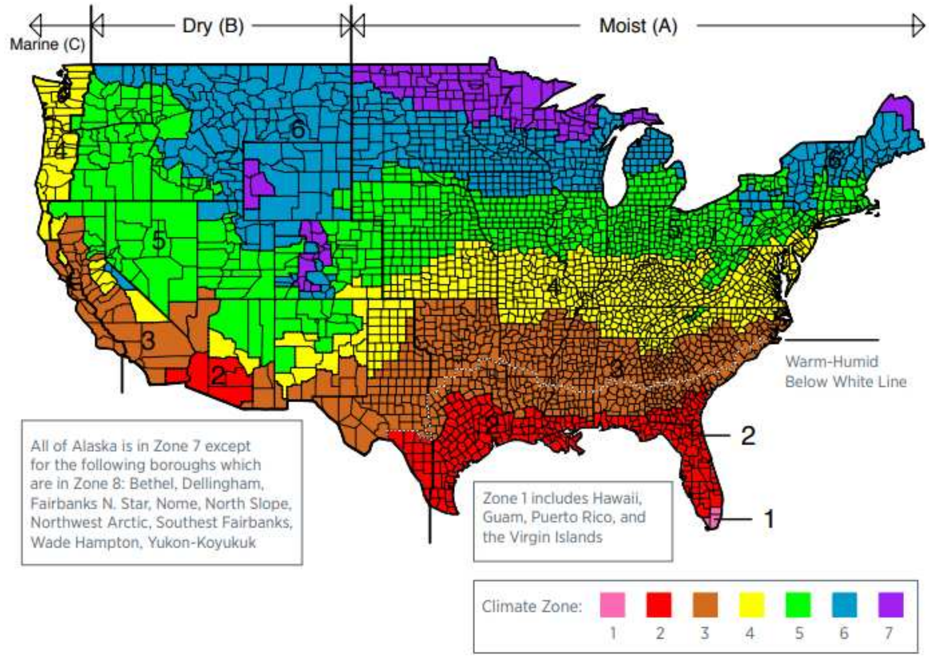


Figure 2-12. Climate Regions of the US showing Denver as Zone 5B, "Cold" and "Dry" [66]

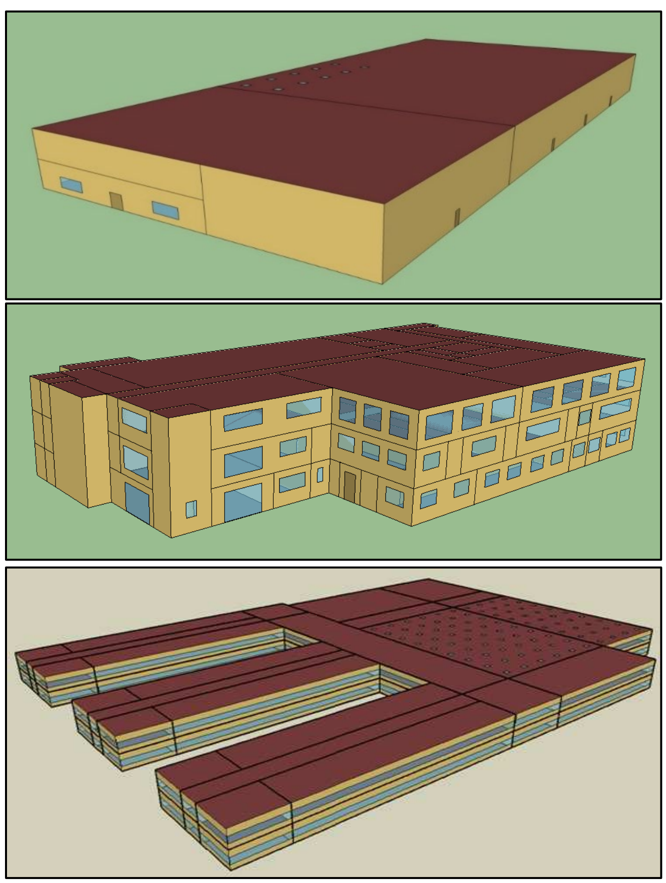


Figure 2-13. IECC Warehouse, Outpatient Healthcare, and Secondary School Building Types used to estimate the hourly load profiles of each building complex in the NWC. [62] *The assigned building types are outlined in Table 2-5.*

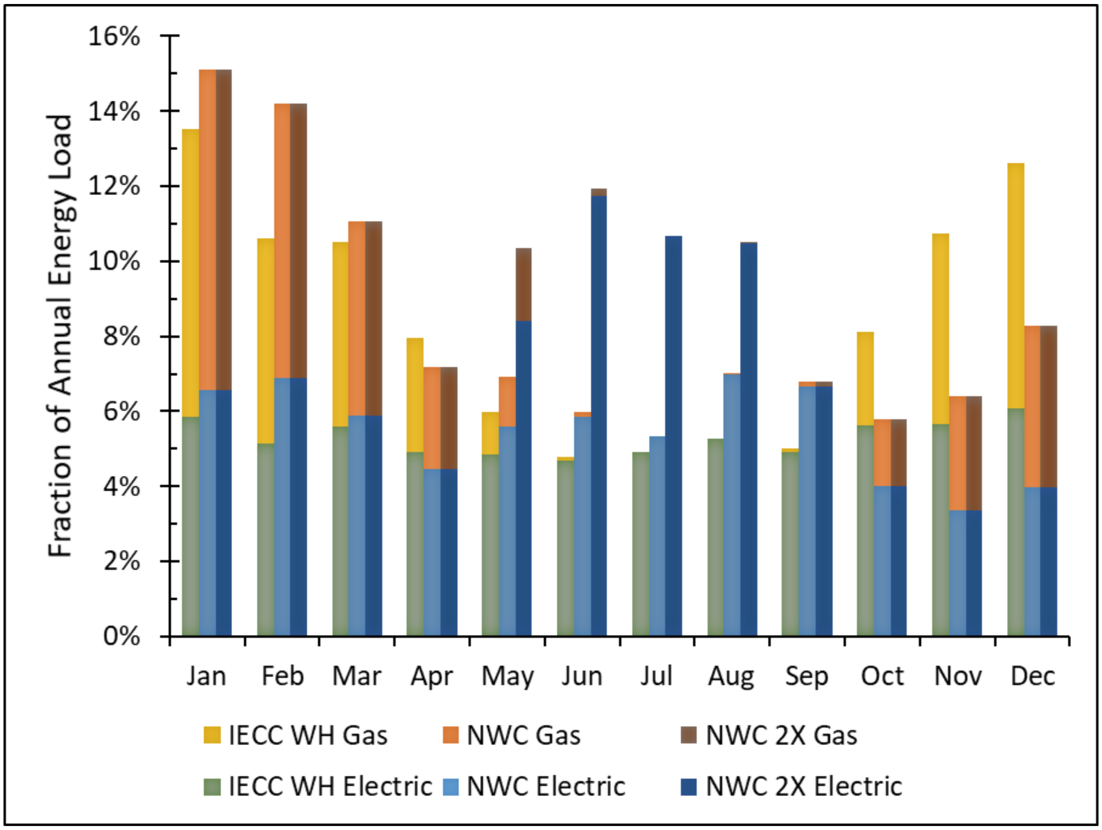


Figure 2-14. NWC "warehouse" building type annual load distribution profile as modified from IECC Warehouse (WH) model. NWC's load is characterized by increased winter and summer use, with decreased load in the fall. The electric-natural gas ratio shifts 64-36% IECC to 66-34% NWC. A 2x summer projected load profile results in a 20% total annual load increase (sums to 120%) with a 70-30% electric-natural gas ratio.

Table 2-3. Preliminary NWC Renewable Technology Feasibility Study Results indicating that PV, biomass, and heat pump are the preferred on-site renewable resources to achieve a net-zero energy campus.

Electrical Technology	**IRR**	**Thermal Technology**	**IRR**
Photovoltaics	7%	Wastewater Heat Recovery	-2%
On-Site Wind	-3%	Biomass	9%
Off-Site Wind	17%	Solar Heating	-13%
		Ground-Source Heat Pump	0%

Table 2-4. Summary of NWC annual energy loads. The 2x Summer profile increases total energy load by 19% over Normal. Implementing Heat Pump (HP) technology increases both the electric load and fraction of electric but reduces natural gas load by more than half such that the total energy load is reduced by 10% for both Normal and 2x Summer profiles.

	Normal	Heat Pump (HP)	2x Summer	2x Summer HP
Electric Load [x10^6 MJ]	44	45	54	55
Natural gas Load [x10^6 MJ]	13	5.5	14	6.0
Total Energy Load [x10^6 MJ]	57	51	67	61
Relative to Normal	100%	90%	119%	108%
Fraction Electric	77%	89%	80%	90%
Fraction Natural gas	23%	11%	20%	10%

Table 2-5. NWC Energy Use Intensity (EUI) Summary (normal load profile) for the various building complexes, including the phase and year for which their energy load and generation comes on-line in the 30-year energy and economic analysis. The healthcare and secondary school EUI are considerably higher than existing buildings, while the warehouse is much lower than the historical buildings, reflective of advances in building construction energy efficiency.

Phase (Year)	Building/Complex	IECC Representative Building Type	Size [m2 (ft2)]	EUI [MJ/m2/yr (kBTU/ft2/yr)]
0 (existing)	Coliseum	n/a – utility bills	16,100 (173,000)	408 (36)
0 (existing)	Stadium/Hall of Education	n/a – utility bills	24,000 (258,000)	508 (45)
0 (existing)	Events Center	n/a – utility bills	23,300 (251,000)	286 (25)
1 (1)	Maintenance (renovation)	Warehouse	5410 (58,200)	183 (16)
1 (1)	Stock Show Arena & Auction	Warehouse	3630 (39,000)	183 (16)
2 (2)	CSU WRC	Secondary School	13,800 (148,000)	490 (43)
3 (3)	Animal Health	Outpatient Healthcare	7240 (77,900)	1180 (104)
4 (6)	Livestock Hall & Arena	Warehouse	30,200 (325,000)	183 (16)
5 (9)	Equestrian Arenas & Paddocks	Warehouse	47,200 (508,000)	183 (16)
Weighted Average:				331 (29)

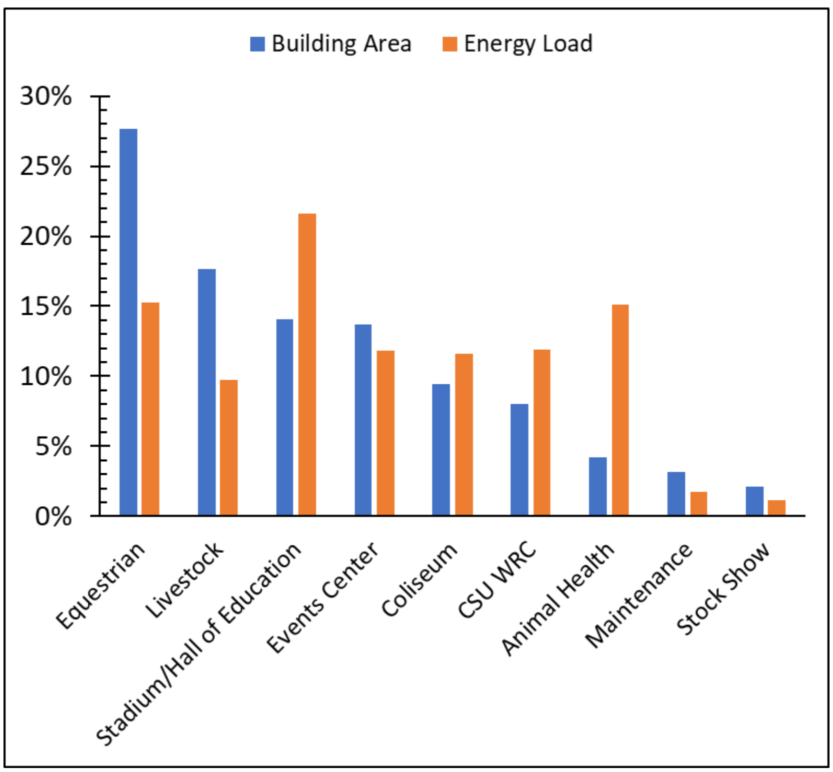


Figure 2-15. NWC campus distribution of building area and energy load. While representing only 12% of building area, the CSU WRC and Animal Health buildings comprise 27% of the energy load. Conversely, the Livestock and Equestrian complexes represent 45% of building area, but only 25% of energy load. The existing Stadium/Hall of Education complex is the largest single building energy load.

Table 2-6. PV Production Estimation per roof segment for the various building complexes of the NWC. The high energy use intensity Water Resource Center (WRC) and Animal Health buildings are unable to generate sufficient PV energy to offset their own needs, while the large area and low energy use intensity Stock Show, Livestock, and Equestrian building generate a surplus of PV energy relative to their own individual energy use.

Building/Use	Size [sq ft.]	Roof Type	# Roof Segments	Available PV Area [m2]	Annual PV Capacity [kWh]	Ratio of Building Energy Needs
Stock Show Arena & Auction	39,000	pitched	4	2740	571,000	310%
Livestock Hall	221,000	pitched	5	11,800	2,520,000	241%
Livestock Arena	103,000	pitched	2	8250	1,730,000	353%
Equestrian Barn	220,000	pitched	3	5440	1,170,000	113%
Equestrian Warm-up (2x)	39,600	pitched	2	1420	297,000	159%
Equestrian Paddock (2x)	61,600	pitched	3	3070	650,000	223%
Equestrian Arena (Sm + Lg)	187,000	flat	2	15,000	2,134,000	242%
CSU WRC (2-story)	148,000	flat	2	5780	821,000	41%
Animal Health	77,900	flat	1	6230	885,000	34%

Table 2-7. Summary Heating, Ventilation, and Air-Conditioning (HVAC) Load table for Ground Source Heat Pump study of CSU's Moby Arena used to determine a cost premium metric ($/kW) for installation of a heat pump system relative to a conventional heating and cooling system.

Building Load	Capacity
Peak Cooling Load	6483 MBh (540 tons)
Peak Heating Load	8266 MBh

Table 2-8. Summary Construction Cost Comparison table for Ground Source Heat Pump study of CSU's Moby Arena used to determine a cost premium metric ($/kW) for installation of a heat pump system relative to a conventional heating and cooling system.

Item	Cost	$/ft2
Alternative 1 (Geothermal) Estimated Cost	$8,400,000	$33.86
Alternative 2 (Conventional) Estimated Cost	$7,224,000	$29.12
Initial Differential Cost	$1,176,000	

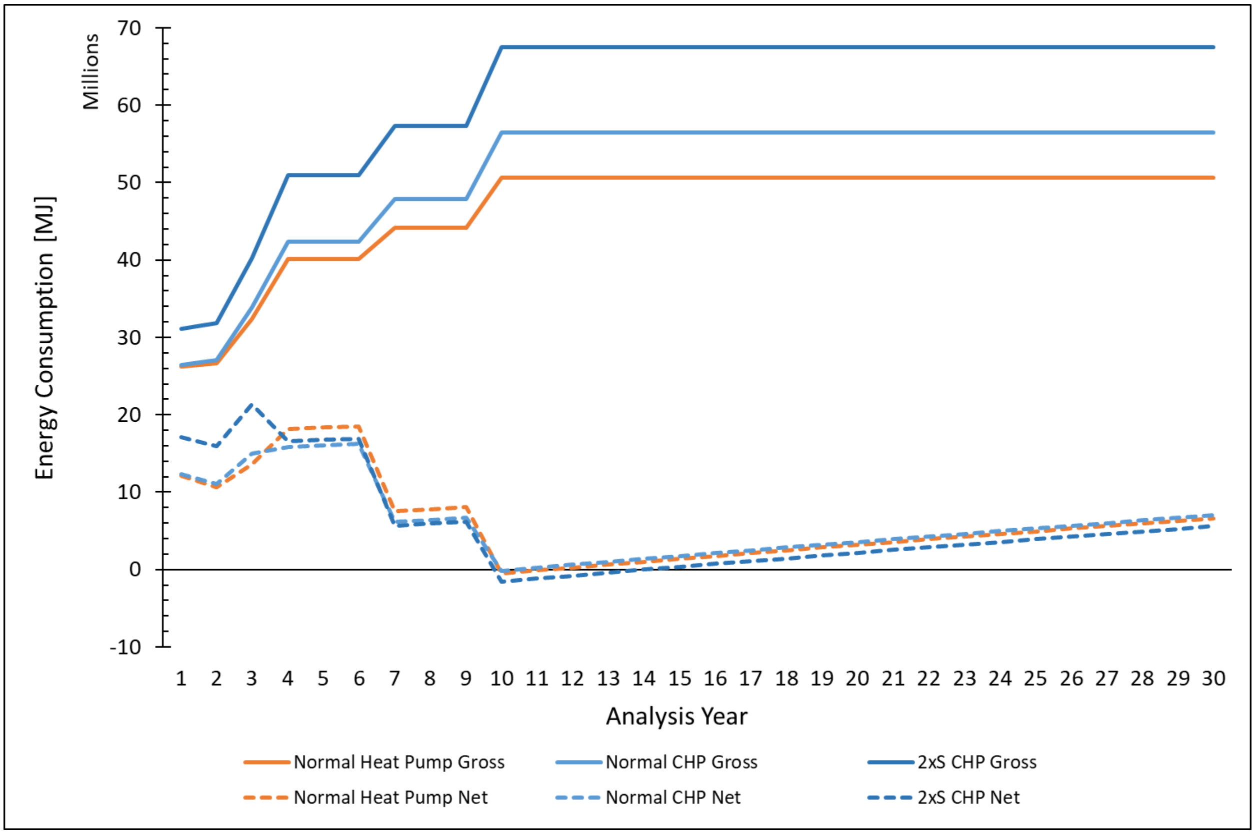


Figure 2-16. NWC annual gross and net energy load over 30-year economic analysis period. Five phases of building construction are considered such that year 10 is the first year reflecting full build-out. Gradual increase in net load over time is reflective of assumed 0.75% degradation in annual PV generation.

Chapter 3. Achieving Optimal Value of Solar: A Municipal Utility Rate Analysis

Wind and solar renewable energy in the United States is projected to triple by 2050 to nearly 30% of total electric energy generation. The upper Midwest region (Iowa, Minnesota, North and South Dakota in particular) is considered wind energy country and not historically known for solar energy development. In this work, Value of Solar (VOS) is developed as a photovoltaic (PV) optimization measure and analysis tool using a northwest Iowa municipality as a representative case study. By applying a top-down load duration curve system analysis, VOS is used to optimize PV orientation and compare electric rate structures for increasing levels of total PV energy contribution. VOS of a fixed south-southwest orientation exceeds the levelized annual costs of installation with a larger net benefit than a one-axis tracking solar system. Production-data modeled VOS is up to 12% higher than Typical Meteorological Year (TMY) predictions, indicating significant correlation between PV generation and peak municipal demand. Compared to alternative time-of-use rates, a demand/energy rate structure better matches VOS economic value and optimal orientation. This VOS methodology is an easy-to-use yet meaningful tool for municipalities and smaller utilities to evaluate strategic installation of and investment in PV for their local community.

Research Question 2: How can PV energy be optimized at a municipal utility level?

Hypothesis 2: A PV system can be designed to specifically offset peak power demands that are typically met by less efficient energy generation. An appropriate energy pricing scheme can economically incentivize such an optimal design.

3.1 Introduction

In the last 30 years, wind and solar renewable energy systems (RES) have grown from a negligible electric generation contribution to just over 9% of U.S. electric generation [4]. In the next 30 years, wind and solar combined are projected to triple in terms of total electricity sector contribution [3], with RES expected to represent nearly 30% of generation. From a grid stability and reliability perspective, broad studies of the Eastern [9] and Western [48] electrical interconnections of the U.S. have concluded that such levels of renewable energy penetration can be integrated without extensive infrastructure changes and would additionally be accompanied by a 25-45% reduction in carbon emissions [8].

Beyond the technical integration details and known environmental benefits, an important consideration for increasing penetration of RES is the economic cost of integrating RES onto the grid. While costs that arise from different physical impacts overlap, it is helpful for understanding to divide these integration costs into three main categories that reflect three specific characteristics of RES: 1) balancing costs due to uncertainty and unpredictability, 2) profile costs due to variability of generation, and 3) grid costs due to location specificity [43].

The first of these costs, balancing costs are mainly operating reserves, which are typically less for solar than wind because the sun is more predictable [42]. The Western Wind and Solar Integration Study (WWSIS) reports that in the 30% renewable energy penetration case, the average variability reserve requirement does indeed double. However, with wind and solar on the system, it is often more economically favorable to back down thermal units rather than decommit them [8]. More specifically the study noted nearly a 1:1 correlation between increased solar production and reduced combined cycle production [44]. This results in increased up-reserves being available without additional capital costs.

In regards to the third type of costs, grid costs, a recent systematic review noted that while specific data is limited, solar grid costs are typically much less than wind since solar is often installed closer to its need [42]. Heptonstall and Gross [42] further concluded that upgrades to transmission and distribution networks are difficult to allocate specifically to RES variability.

Profile costs thus emerge as the largest and most significant integration costs. These costs are linked to the temporal variability of RES with an uncontrollable output not necessarily correlated to demand [43]. Factors contributing to these costs are low RES capacity factors, and increased ramping and reduced load factors for conventional generation. While it has been shown that the direct economic impact of cycling is small, the largest single factor of integration costs is the resulting reduced utilization of capital embodied in thermal plants [43]. From a mixed cost/benefit perspective, these profile costs can be regarded as reducing the value of RES energy because they reflect diminishing avoided costs of conventional generation [43]. A methodology used to measure this changing value of PV added to the grid is Value of Solar (VOS) [13].

VOS follows a methodology more broadly defined for all distributed generation renewable energy resources called Value of Resource (VOR) [94]. VOS is VOR applied specifically to solar resources and was initially developed as rate design mechanism intended to measure the true value of solar PV generated electricity. While there is ample data available on fuel and wholesale retail electricity costs [49,50], there is a lack of consensus on what renewable energy is worth. Beyond the obvious benefit of fossil fuel saved, VOS also considers avoided capacity, transmission & distribution cost deferral, and environmental benefits [13,51]. Past VOS studies have been leveraged to define a consumer energy rate for RES generation somewhere between the extremes of net-metering and displaced fuel costs [13,14,94–97]. VOS has also been analyzed for utility scale PV for 10,000 U.S. locations from 2010 to 2017 using historical nodal electricity prices, capacity market prices, marginal power system emissions, and Typical Meteorological Year (TMY) weather data to classify the value of PV in terms of displaced energy, capacity, public health, and climate change [52]. It is noted that this VOS data tends to be clustered in the Northeast, West (particularly California), and Texas. There is a notable lack of data in the upper Midwest region.

The upper Midwest (Iowa, Minnesota, North and South Dakota in particular) is considered wind energy country and is not historically known for solar energy development. However, recent analysis suggests that a mix of solar and wind additions would be more beneficial going forward [5], and that wind and PV energy can complement one another in daily and seasonal trends [6]. Where there is a strong correlation between PV output and summer daytime peaks, adding solar PV can help make the system more reliable and/or reduce the cost of meeting peak demand [42], such that integration costs can even be negative at low (<10%) RES penetration [43].

Characterizing RES integration costs as additional expenses to be added to system generation costs has been described as a bottom-up engineering view of power system operation [42]. This work seeks to take a top-down engineering view of power system operation by analyzing the system load duration curve (LDC) before and after renewable contribution (residual LDC or RLDC) to characterize RES in terms of the value it adds to the system. A case-study is conducted for Sioux Center Municipal Utilities (SCMU) in northwest Iowa, which services more than 2700 electric customers including mix of residential, commercial, and industrial sites. In this way, this local analysis of SCMU can be representative of the larger upper Midwest geographical area. This works seeks to leverage the broad system considerations encompassed in VOS methodology to advance VOS as a system design benchmark and optimization tool.

PV optimization studies have performed before. A non-constrained nonlinear optimization (‘fminsearch’ function in MATLAB [53]) was used to find the local maximum global hourly irradiation as a function of panel tilt and azimuth for locations across the continental U.S. Mapped results indicate an approximate optimum tilt of 37° from horizontal and azimuth 2° west of South (182°) for the geography of Northwest Iowa [54]. Noting that higher summer electricity prices tend to drive azimuth west and tilt towards the horizontal, a subsequent study compared PV energy peak to market value peak using TMY weather, inverter modelling, and time-of-use rates throughout the continental U.S. as a proxy for average local grid conditions [55]. Energetically the optimal azimuth was consistently within 10° of South for 90% of 1020 locations, while the max value of energy was found to shift more than 10° west of South for nearly half of the locations. The TMY data max energy and value azimuths for northwest Iowa both remained within 10° of South, meaning the analysis did not find an economic incentive to significantly reorient the PV array.

The focus of this work is to develop VOS as an optimization measure and analysis tool used to calculate specific VOS for the upper Midwest based on real PV production data. By applying a top-down load duration curve (LDC) system analysis, integration costs are defined from a value perspective that captures the changing value as PV contribution increases on the grid. Defining VOS in this way allows for PV system design optimization as well as a benchmark against which different electric rate structures can be analyzed and compared. The methodology applied is considerably simpler than a full capacity-expansion system model [45], yet it provides key insights and trends consistent with findings from such studies [9,46–48]. As presented, this VOS methodology is an easy-to-use yet meaningful tool for municipalities and smaller utilities to evaluate investment in and guide design of PV in their local community.

3.2 Method

This work uses VOS methodology to optimize system design at varying levels of PV energy contribution for Sioux Center Municipal Utilities (SCMU) in northwest Iowa, USA. The PV system is optimized for orientation: azimuth angle (East = 90°, South = 180°, West = 270°) and tilt (0° = horizontal, 90° = vertical) based on VOS modeled from real production data. PV generation is modeled from local PV production data of a south-facing system comprised of four different tilt angles. The production data model is calibrated with generation data from three of the four tilt angles and validated against the fourth to quantify model uncertainty. Model uncertainty is propagated using Monte Carlo methods to demonstrate statistical confidence in the optimal cost savings advantage.

PV system contribution is modeled at marginal (0.1%), low (4%), medium (10%) and high (25%) levels as measured in terms of total energy generation for a nominal south-facing 41° tilt PV installation. The low value of 4% was chosen to match the current SCMU wind energy proportion [98] as well as the baseline value of the WWSIS as given by the Transmission Expansion Planning Policy Committee [47]. The high value of 25% was chosen to match the high solar case of the WWSIS [46]. The medium value of 10% was selected as a reasonable middle value and previously identified as a contribution level above which solar generation can result in overproduction [99].

3.2.1 Value of Solar (VOS)

VOS is calculated as the sum of net cost benefits in five major categories [13] utilizing several calculation methods [51] as outlined in Table 3-1. The result is presented as seven separate components which sum to give the full VOS cost savings benefit: fuel, variable operations and maintenance (VOM), capacity credit, fixed operations and maintenance (FOM), transmission and distribution (T&D), losses, and environmental (CO2). VOS is presented as energy normalized ($/kWh) or capacity-normalized (annual $/kW).

Table 3-1. Value of Solar (VOS) categories characterized as the sum of net benefits [13] in five major categories and listed alongside the calculation method [51] employed for seven components of net benefits in this study.

Category	Net Benefit	Calculation Method
Energy	Avoided fuel and variable costs	LDC-RLDC (1) Fuel Costs (2) VOM
Generation Capacity	Avoided fixed costs of new generation	LDC-RLDC (3) Capacity Credit, (4) FOM
T&D Capacity	Avoided cost of building & maintaining T&D infrastructure	(5) T&D Levelized cost on Capacity plus T&D Variable cost on Energy
T&D Losses	Avoided losses from remote generators	(6) Transmission Loss Multiplier on PV generation
Environmental	Reduced air emissions	(7) CO_2 social cost $39/ton [24]
Acronyms: CF = Capacity Factor; FOM = Fixed Operations & Maintenance; LDC = Load Duration Curve; RLDC = Residual LDC; T&D = Transmission & Distribution; VOM = Variable Operations & Maintenance		

Fuel and VOM savings are calculated based on the assumption of natural gas combined cycle (CC) power plants for base and intermediate load and natural gas combustion turbine (CT) power plants for peak power using nominal performance data from the EIA Annual Outlook [49] and natural gas prices averaged over the five-year period of the c. This is considered a conservative calculation given that existing power plants may operate at lower plant efficiency and different fuels (i.e. coal) compared to new CC and CT natural gas designs. Capacity credit and FOM cost savings are calculated using the overnight build and operating costs for new plants [49], while T&D savings are a combination of avoided fixed transmission costs for new plants as well as variable maintenance costs on existing infrastructure [100]. Avoided energy losses for local PV generation source versus a remote generator are calculated as a 7% multiplier on all PV generated energy [13]. Environmental cost savings are calculated from typical emissions for CC and CT power plants [101,102] and a published $39/ton social cost of carbon value [24] corresponding to the time frame of the PV production data.

Some studies expand environmental benefits of renewable energy to include public health benefits afforded by improved air quality [103]. Monetization methods consider the health benefits of better air quality (i.e. reduced mortality) coupled with the perceived value of avoiding premature adult mortality, known as the value of statistical life (VSL) [103,104]. The resulting energy normalized total environmental benefit can be quite high in geographical regions with significant particulate, NO_x, and SO_x emissions from conventional fossil generation (i.e. \$0.02 to \$0.07/kWh in the Upper Midwest), with up to 95% of this total environmental benefit attributed to VSL [103]. However, since VSL health benefits are relatively subjective in nature and are not included in standard VOS methodology [13], they also not included in this analysis.

It is also recognized that emissions of conventional generation include more than just CO_2. However, considering just natural gas conventional generation (as assumed in this study), the environmental emission benefits (including NO_x and SO_x) are found to be over 90% attributed to CO_2 [13]. Coupled with the fact that CO_2 emissions are known to increase when backing down fossil fuel thermal plants [102], this study conservatively estimates the environmental benefits as simply the social cost of carbon associated with natural gas fuel savings.

3.2.2 Load Characterization

Municipal electric load is characterized using a Load Duration Curve (LDC) which plots energy demand in descending order versus relative duration. An LDC plot can be made both before and after the impact of the PV system is determined, with the after plot being called a Residual LDC (RLDC). The LDC and RLDC plots are used to characterize the electric load in terms of peak, intermediate, and base capacities based on a 15-60% division of relative duration [105]. A capacity factor (CF) is calculated for each load range, which is used in calculating levelized cost of energy (LCOE) for each type of conventional generation using methods outlined in the Financial Analysis section. A sample LDC and RLDC plot is shown in Figure 3-1, including an overlay of the base, intermediate, and peak load determination for the LDC. Also included on the plot are the three major changes from the baseline LDC to a PV RLDC: 1) a peak capacity credit (peak load power is reduced), 2) a reduction in CF most noticeable in the base load, and 3) a potential for overproduction as the PV system capacity is increased [99]. The RLDC curves on the plot are generated prom PV production data of a south-facing 41° tilt system.

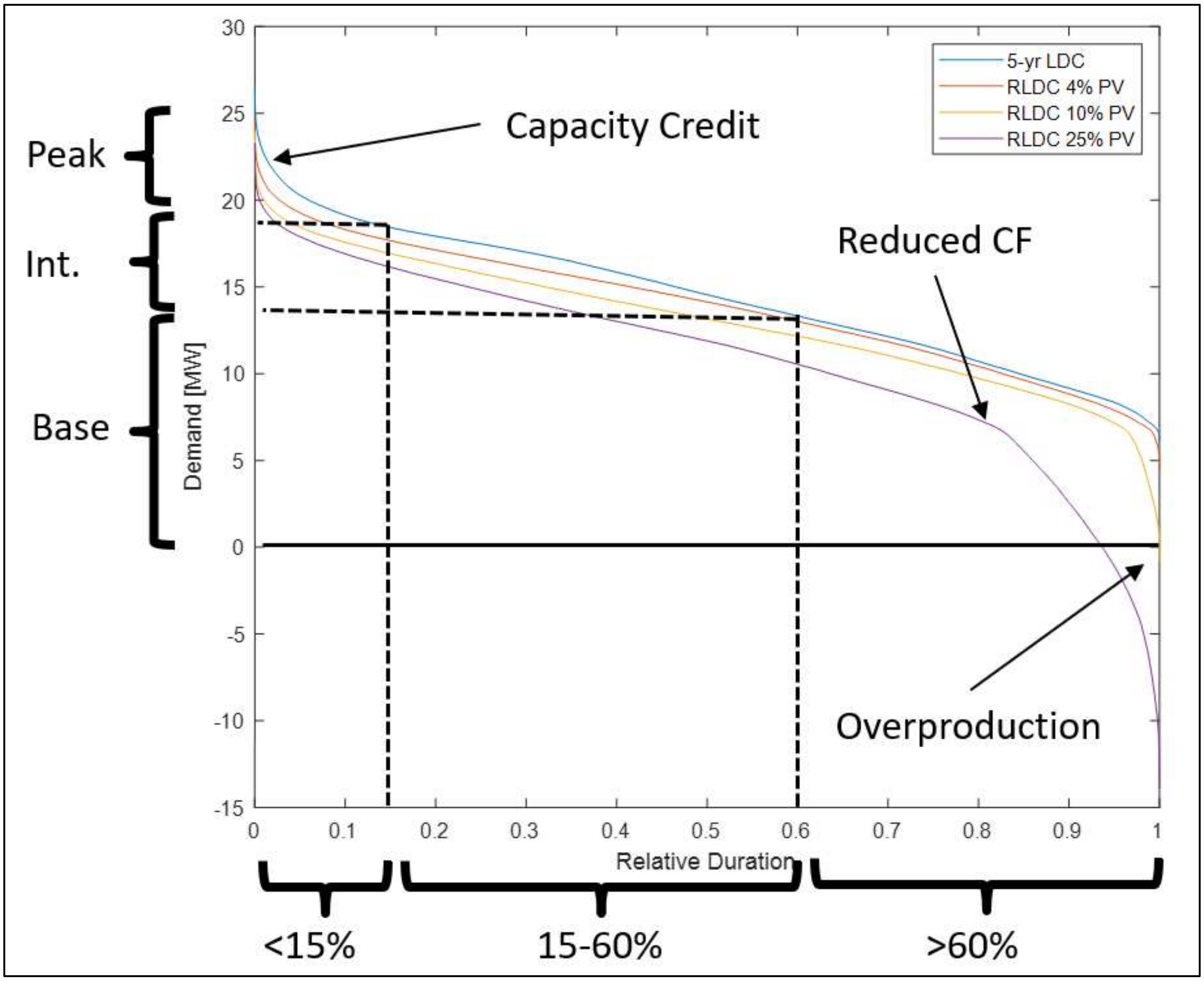


Figure 3-1. Load Duration Curve (LDC) and Residual LDC (RLDC) curves illustrating peak/intermediate/base load determination based on 15-60% relative durations. RLDC plots with solar contribution show the resulting capacity credit, reduced capacity factor (CF), and overproduction impacts of increasing PV energy contribution.

3.2.3 PV Optimization and Uncertainty

PV generation is modelled based on local production data from a PV system within the SCMU geographical boundary. This system features south-facing panels at four different tilts (16, 29, 41, and 65° from horizontal), allowing differences in production to calibrate a beam and diffuse irradiance and system efficiency model for predicting alternative system orientation performance. Data from three tilts (16, 41, and 65°) are used to calibrate and verify the model, which is validated against the 29° tilt data. Calibrated irradiance and efficiency model data is used to optimize panel tilt and azimuth for maximum VOS or annual cost savings for a particular electric rate structure.

A system model diagram for the PV optimization is shown in Figure 3-2. The design variables include PV system capacity (Cap), combined panel/inverter system efficiency (η), panel tilt from horizontal (β), panel azimuth angle from South (γ), and the local solar irradiance (beam I_b and diffuse I_d). The desired output is a normalized annual cost savings in $/kW of PV capacity. If local solar irradiance data is available, system efficiency can be assumed to estimate PV energy production and net energy costs. However, in this modeling scenario, PV production data at different tilts is used in an iterative calibration to model the solar irradiance and system efficiency that best matches the production data. With the calibrated solar irradiance and panel efficiency variables, PV tilt and azimuth can be varied to optimize the annual cost savings of the PV system.

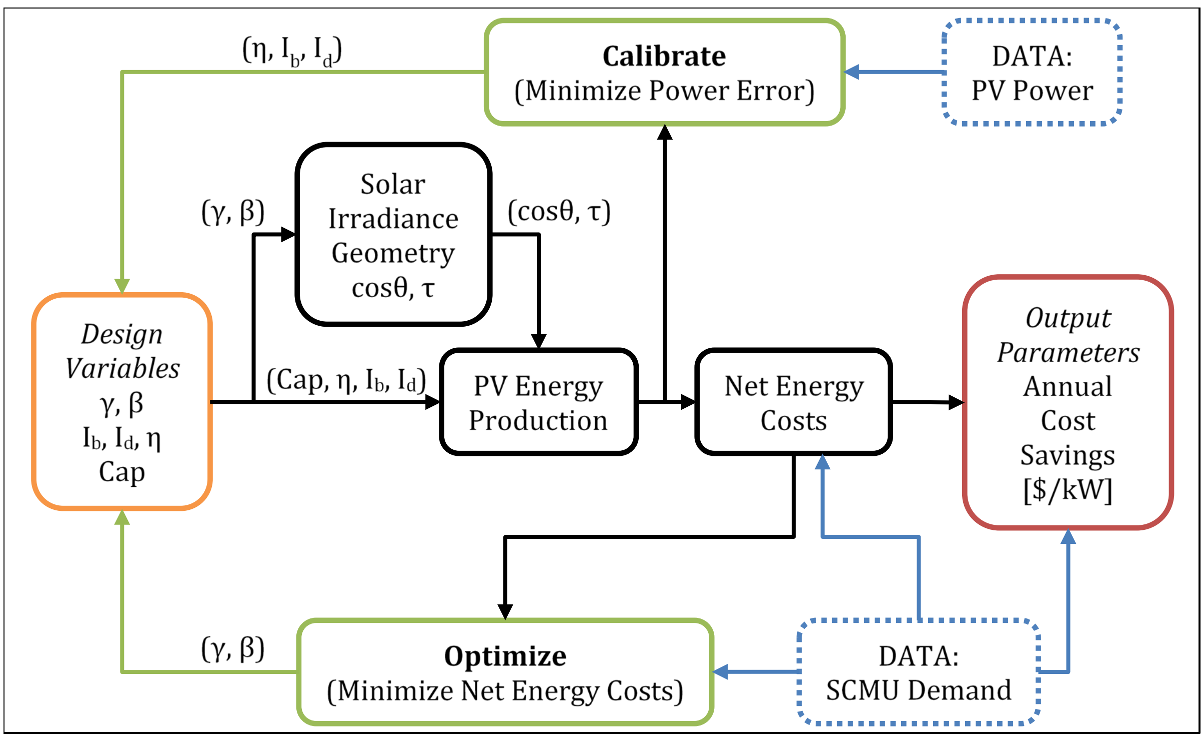


Figure 3-2. PV optimization system model diagram showing input data of electric load/demand and PV Power. Two iterative processes are leveraged. First the energy production model is calibrated to best fit the PV production data. Then the PV orientation is varied to optimize the energy cost savings.

PV energy production is modeled with as a combined panel/inverter system conversion efficiency multiplied by the incoming solar irradiation. Solar irradiation is typically broken down into separate beam (direct) and diffuse (indirect) components, such as outlined in Eq. 1 [106], where the total irradiation (I_T) is split into a beam (b) and diffuse (d) sources including isotropic (iso), circumsolar (cs), horizon (hz), and reflected (refl). Generation data is modeled as PV system efficiency and beam and diffuse irradiation values based on the Perez et al. anisotropic sky radiation model [107], the same model used by NREL in PVWatts [79]. In Eq. 2, the individual components of total radiation are defined in terms of incidence angle (θ), solar zenith angle (θ_z), circumsolar and horizon brightness coefficients (F_1, F_2), panel tilt (β), ratio of incidence-weighted circumsolar irradiation ($\frac{a}{b}$), and ground reflectance coefficient (ρ_g) [107,108]. The PV power production (P) is calculated with the system efficiency (η), module area (A_m), and transmission (τ_g) parameters applied explicitly to separate beam and diffuse terms as shown in Eq. 3.

$$I_T = I_{T,b} + I_{T,d,iso} + I_{T,d,cs} + I_{T,d,hz} + I_{T,refl}$$

Eq. 1

$$I_T = I_b \frac{\cos\theta}{\cos\theta_z} + I_d(1 - F_1)\left(\frac{1 + \cos\beta}{2}\right) + I_d F_1 \frac{a}{b} + I_d F_2 \sin\beta + I\rho_g\left(\frac{1 - \cos\beta}{2}\right)$$

Eq. 2

$$P = \eta A_m \left[\left[\tau cos\theta + \cos\theta_z\left(\frac{1-\cos\beta}{2}\right)\rho_g\right] I_b + \left[(1 - F_1)\left(\frac{1+\cos\beta}{2}\right) + F_1\frac{a}{b} + F_2\sin\beta + \left(\frac{1-\cos\beta}{2}\right)\rho_g\right] I_d\right]$$

Eq. 3

The PV computational model is programmed in MATLAB [53]. The model calibration function is used to minimize the error from PV data subject to penalty constraints to keep irradiation terms positive and system efficiency between 1 and 20% [109]. PV tilt and azimuth are varied in separate optimization programs to 1) maximize VOS, and 2) minimize net annual energy costs (i.e. maximize cost savings) based on a defined utility rate.

Error associated with the model is quantified in terms of root mean square error (RMSE) and standard deviation. The standard deviation is used in a Monte Carlo analysis to generate statistical 90% confidence intervals for the uncertainty of the modeled VOS and annual cost savings. Monte Carlo simulations of 100, 200, 400, and 800 runs are conducted to demonstrate convergence of the confidence interval uncertainty.

The PV system optimization model is also run with Typical Meteorological Year (TMY) irradiance and system efficiency data available through PVWatts [61]. Production data model results are compared to TMY to examine differences in VOS, annual cost savings, and optimal fixed system orientation. PVWatts default fixed open rack mounting PV parameters (module type, DC to AC ratio, inverter efficiency, ground coverage ratio) are assumed for TMY data, with DC losses adjusted to equalize annual production data and TMY as shown in Table 3-7.

3.2.4 Alternate Rate Structures

VOS optimized results are compared to a second PV design optimization to maximize annual cost savings for various electric rate structures for SCMU. The existing demand/energy (D/E) price structure is outlined in Table 3-2. The demand listed in the table is a combination of demand and transmission charges, both of which are proportional to the peak energy demand of the month. The demand rate is seasonal, being highest in the summer, lowest in the spring and fall, and in between for winter months. The energy charge per kWh stays the same throughout the year.

Table 3-2. Existing demand/energy rate structure for Sioux Center Municipal Utilities

Months	Demand plus Transmission [$/ kW]	Energy [$/kWh]
DEC, JAN, FEB	22.00	0.0315
MAR, APR, MAY	16.50	
JUN, JUL, AUG	27.00	
SEP, OCT, NOV	16.50	

By examining the seasonal, monthly, weekly, and daily trends of SCMU electrical demand, alternate Time-of-Use (TOU) and Rate-of-Use (ROU) structures are designed for comparing PV cost savings to the D/E rate structure and VOS benchmark. Since a switch to TOU rates is being considered for SCMU, two TOU rate structures were designed to be applied from May to October. A midday rate (TOUm) has a peak rate applied weekdays from noon to 6:00 pm local time, and an intermediate rate from 7:00 am to noon and 6:00 pm to 9:00 pm. An evening rate (TOUe) has a peak rate applied from 3:00 pm to 9:00 pm. The ROU structure is set by power demand, with peak and intermediate levels determined from the municipal LDC. The intermediate and peak rates feature a multiplier of the base rate ($/kWh), which is calculated to generate equivalent revenue for the period of analysis.

3.2.5 Financial Analysis

Financial calculations and analyses are consistent with methods outlined and exemplified in NREL's Annual Technology Baseline [81]. Levelized annual cost (LAC) is used to determine annual cost savings associated with the capacity credit of the PV system. LAC is defined in equations Eq. 4 through Eq. 6.

$$LCOE = (FCR * CAPEX + FOM)/(CF * 8760) + VOM + Fuel$$

Eq. 4

$$LAC = LCOE * CF * 8760$$

Eq. 5

$$LAC = FCR * CAPEX + FOM + CF * 8760 * (VOM + Fuel)$$

Eq. 6

LCOE is Levelized Cost of Energy, FCR is Fixed Charge Rate, CAPEX is Capital Expenditures, FOM is Fixed Operations and Maintenance, CF is Capacity Factor, VOM is Variable Operations and Maintenance, and LAC is Levelized annual Cost. FCR on capital investment is calculated using the economic assumptions and parameters outlined in Table 3-3.

Table 3-3. Economic analysis inputs, assumptions, and calculated rates following the model of NREL's annual technology baseline [81]*. The Weighted Average Cost of Capital (WACC) is the discount rate used in the net present value analysis. Inflation is the difference between nominal and real rates (nominal includes inflation). The fixed charge rate (FCR) is used in calculating the value of PV capacity credit in the annual savings, and depreciation is calculated with a 5-year Modified Accelerated Cost Recovery System (MACRS) model.*

Parameter		Value
Assumptions / Inputs	Inflation (i)	2.5%
	Debt Interest Rate (IR)	5%
	Rate of Return on Equity (RROE)	10%
	Debt Fraction (DF)	60%
	Tax Rate, federal + state (TR)	27%
	Loan Term, years	10
	Period of Analysis, years (t)	25
	Depreciation	MACRS-5
	Annual PV degradation	0.60%
Calculated	WACC, Nominal	6.2%
	WACC, Real	3.6%
	Fixed Charge Rate (FCR)	6.5%

PV installation is investigated as a financial investment for SCMU using the existing D/E rate structure. The analysis is done two different ways: simple payback and zero net present value (NPV). For simple payback, the total PV system cost is divided by the annual cost savings to yield the number of years to recoup the installation investment. No inflation, loan terms, or other rate-of-return factors are included in simple payback. In the zero NPV analysis, the financial parameters of Table 3-3 are used except for the Rate of Return on Equity (RROE). Instead, a RROE is calculated to yield a zero NPV over the 25 years of analysis. Inflation is applied to the analysis as an increase in annual cost savings and maintenance costs, and the cost of replacement inverters is added into year 12 of the analysis. Based on the zero NPV RROE, nominal and real Weighted Average Cost of Capital (WACC) are calculated.

3.3 Results & Discussion

Results are organized into four main sections. The VOS Optimization section shows that an optimal fixed south-southwest PV orientation generates higher VOS than both fixed south-facing PV and horizontal one-axis trackers. TMY predicted VOS is shown to be significantly undervalued compared to the production data model. In the Orientation Optimization section, the optimal azimuth and tilt of the D/E rate structure best matches the optimized VOS benchmark. In the Rate Optimization section, a D/E rate is customized to better match VOS results. Finally, in the Investment Analysis section, annual energy cost savings of PV systems exceed the levelized annual cost of installation such that up to 13% RROE can be achieved.

3.3.1 VOS Optimization

VOS is calculated for south facing 41° tilt, horizontal one-axis tracking, and an optimized fixed orientation (azimuth and tilt) in Figure 3-3. VOS is energy normalized ($/kWh) and divided into the seven component net benefits listed in Table 3-1. VOS decreases, as expected, as total energy contribution increases from marginal (0.1%) to high (25%) PV energy contribution. The VOS decrease can be specifically noted in the capacity credit and FOM components and is consistent for both fixed and one-axis orientations. Fuel, VOM, and CO_2 components remain relatively constant as PV energy increases, while T&D and losses components of VOS have an intermediate reduction as they are proportional to both the displaced energy and capacity credit of the PV system.

Energy normalized VOS is highest for the optimal fixed orientation, which achieves the highest capacity credit. The slightly higher fuel and VOM benefits of the optimal fixed orientation indicate that more of the peak energy (i.e. displaced CT energy) is being met by solar compared to the other orientations. What is not captured with energy normalized VOS is the total annual energy produced by the optimal fixed orientation is the lowest, while the one-axis orientation produces the highest annual energy. This is addressed by considering capacity normalized VOS based on annual benefits as well as levelized annual costs (LAC) for PV installation [110].

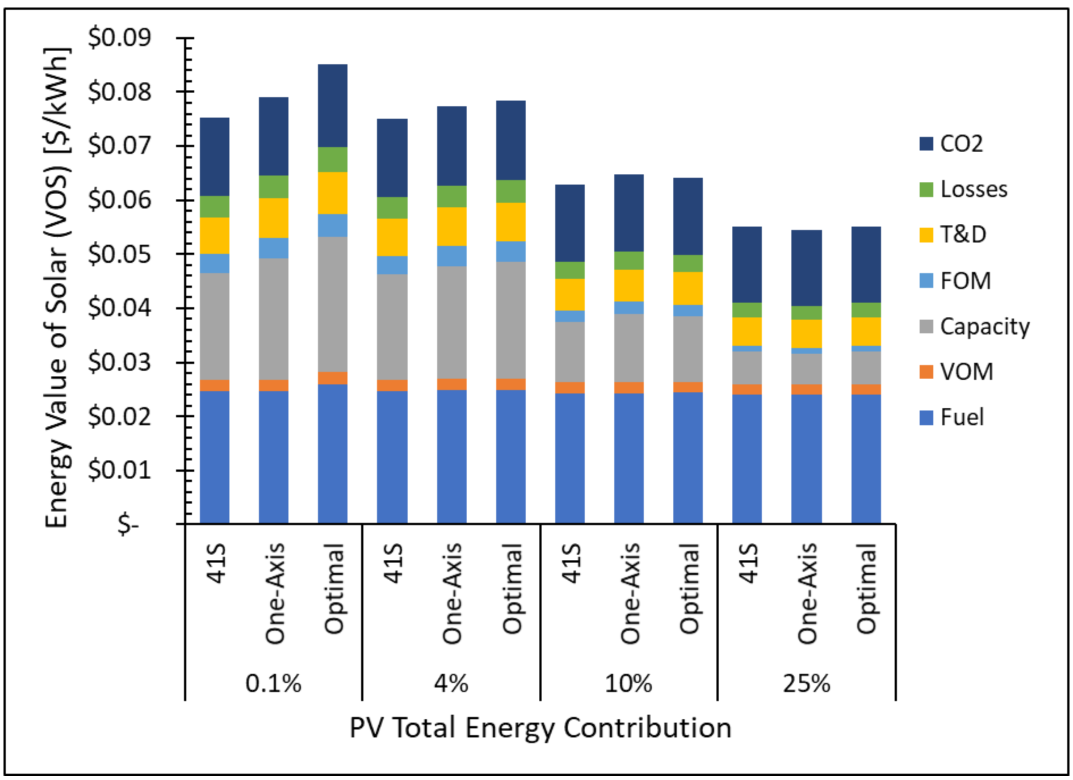


Figure 3-3. Value of Solar (VOS) for south facing 41° tilt (41S), horizontal one-axis tracking (One-Axis), and optimal fixed orientation (Optimal) systems. VOS is broken down into fuel, variable operation and maintenance (VOM), capacity credit, fixed operations and maintenance (FOM), transmission & distribution (T&D), transmission losses, and environmental carbon credit (CO2). The optimal fixed orientation produces highest energy normalized VOS in most cases.

Combined VOS and LAC are presented in Figure 3-4 as capacity normalized annual benefits/costs ($/kW). VOS is plotted as positive and LAC as negative such that their sum is the net value. The one-axis system has the highest capacity normalized VOS owing to its highest annual energy production. However, the one-axis system also has the highest LAC due to the added complexity of tracking. When the VOS and LAC are combined to yield the net value, the optimal fixed orientation remains the highest. The net value at marginal PV contribution (0.1%) is large and negative because PV costs per capacity are higher in small systems. The net value is also negative at high PV energy contribution (25%) due to a decreasing capacity credit of the system VOS. The 4% PV case has the highest normalized net benefit since VOS remains high while the PV cost per capacity is substantially less than the marginal (0.1%) case.

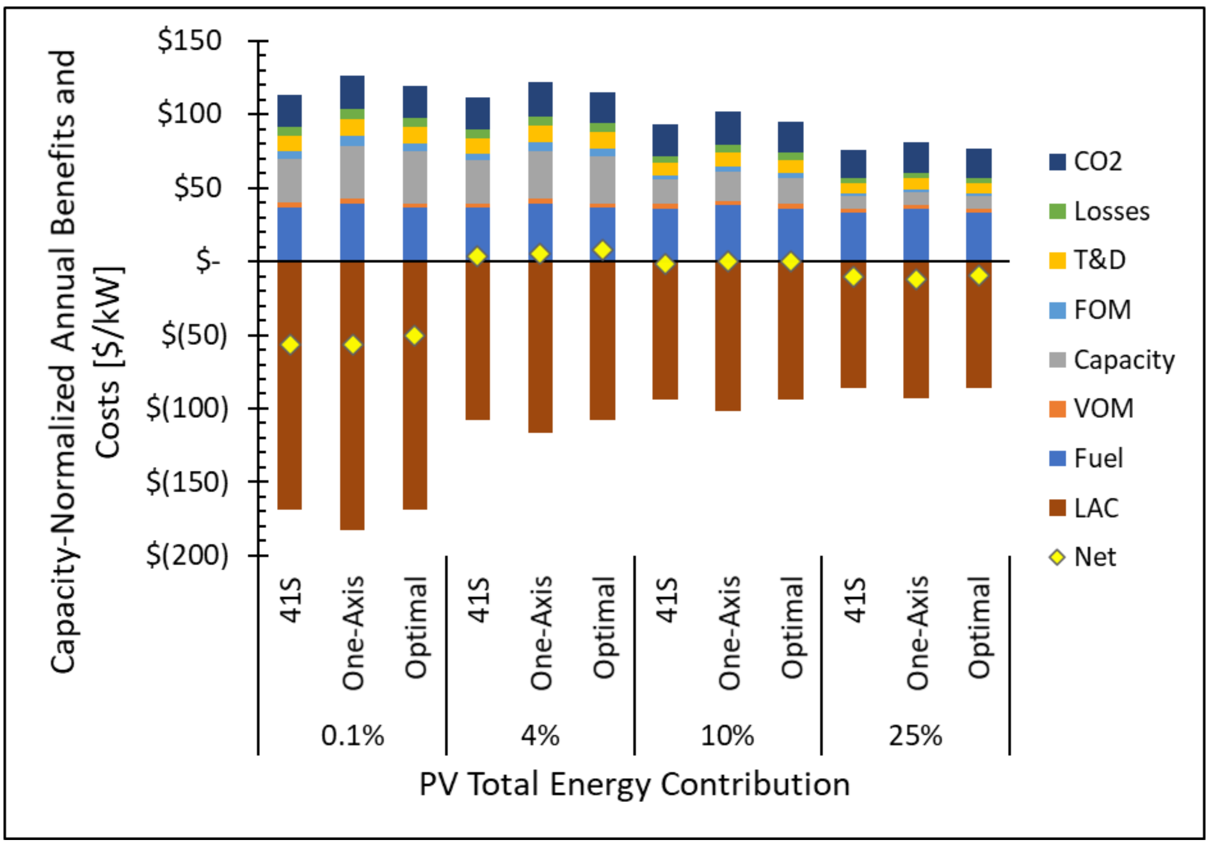


Figure 3-4. Capacity normalized annual ($/kW) combined Value of Solar (VOS), Levelized Annual Cost (LAC) and net value (VOS – LAC) for south facing 41° tilt (41S), horizontal one-axis tracking (One-Axis), and optimal fixed orientation (Optimal) systems. VOS is broken down into fuel, variable operation and maintenance (VOM), capacity credit, fixed operations and maintenance (FOM), transmission & distribution (T&D), transmission losses, and environmental carbon credit (CO2).

Production data model VOS results are compared to TMY solar prediction from PVWatts [61]. TMY VOS was calculated for a fixed 41° tilt south facing system, one-axis tracker, and an optimized fixed orientation. Results are presented in Figure 3-5 as the difference between the production data model and TMY, where a positive result means the production data model VOS is higher. Except for the marginal (0.1%) one-axis case, the production data VOS consistently has a higher capacity credit than TMY representing the largest categorical difference. The 8% capacity credit difference and nearly 12% total difference at low PV energy contribution (4%) stand out as particularly significant and supporting evidence of a strong correlation between maximum PV system generation and peak municipal energy demand. In the 4 and 10% one-axis cases the difference is split by category with fuel, VOM, and carbon credit negative while capacity credit, FOM, and T&D differences are positive. This results from higher total annual energy for the one-axis TMY prediction than the production data model (see Table 3-7). The total VOS difference in these cases remains positive due higher production data capacity credit. The total VOS difference is negative for 25% PV contribution since the production data model results in more over-production than TMY which makes energy-based cost differences net negative for all orientations.

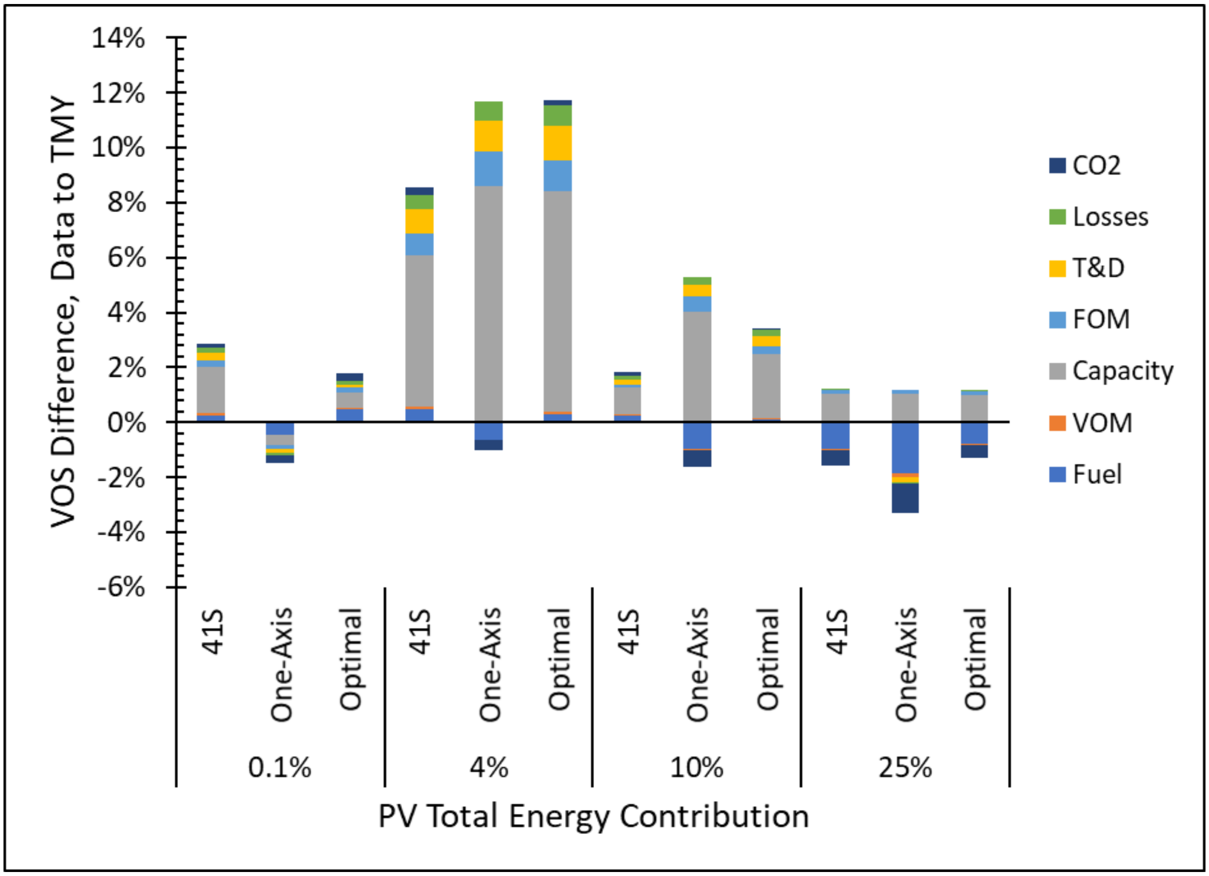


Figure 3-5. Difference in Value of Solar (VOS) for the production data model versus Typical Meteorological Year (TMY) solar prediction. Differences in category (fuel, VOM, capacity, etc.) are plotted as negative or positive, with positive indicating that production model VOS is higher than TMY prediction.

The underlying cause of the VOS difference between the production data model and TMY prediction is compared in more detail in Figure 3-6 for the optimal fixed orientation systems. The comparison is based off the Residual Load Duration Curve (RLDC) for each scenario such that residual conventional generation can be broken down into base, intermediate and peak generation. The difference between the RLDC and original LDC peak demand is the capacity credit. The capacity credit decreases quite dramatically with increasing PV energy contribution from over 65% in the marginal (0.1%) case to less than 15% in the high PV energy contribution case. The relative reduction of peak generation capacity is highest for 4% PV energy contribution, and the capacity credit transitions to more displaced base generation at 25% PV energy contribution. Comparing the production data model and TMY prediction, the largest difference is in the 4% PV energy case, where the production data model capacity credit remains over 60% while the TMY prediction is closer to 40%. This difference explains much of the 12% VOS difference observed in Figure 3-5. Another key observable difference between the production data model and TMY prediction is the production data model has a consistently lower RLDC peak capacity, which is again evidence of the correlation between maximum PV system generation and high municipal energy demand.

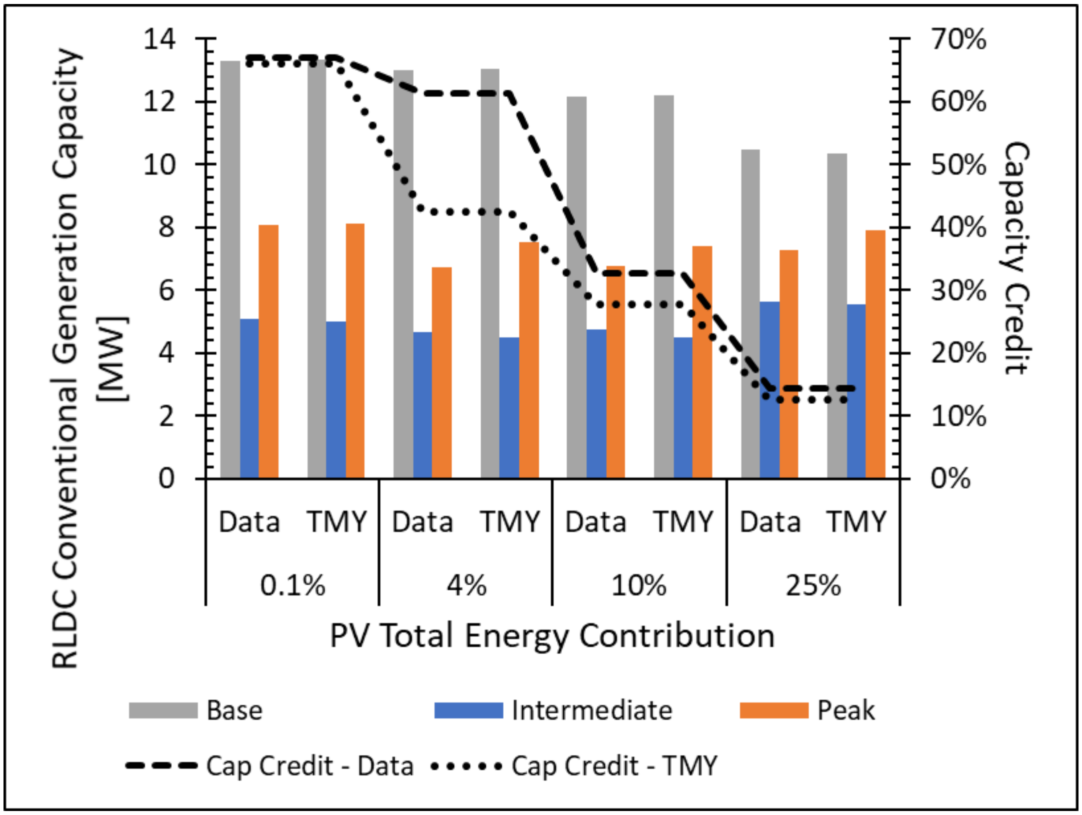


Figure 3-6. Residual Load Duration Curve (RLDC) conventional generation capacities for the optimal Value of Solar (VOS) fixed orientation system. Solar capacity credit is above 60% for PV energy contribution less than 4%, but decreases to below 15% for 25% PV energy contribution. Base generation is most significantly reduced at 25% PV energy contribution.

3.3.2 Orientation Optimization

Alternate TOU and ROU rates were set following the methods outlined in the Alternate Rate Structures section. The resulting equivalent revenue base rates are shown in Table 3-4. Multipliers for intermediate and peak rates were set at 1.4 and 2.1, respectively, based on the relative levelized costs for intermediate and peak conventional generation energy as defined by the municipal LDC (see Figure 3-16). These multipliers are consistent with published TOU rate structures in California and Ontario, Canada [111,112]. Based on the LDC, the SCMU ROU base rate is applied for demand less than 13,322 kW, the peak rate is triggered above 18,417 kW, and the intermediate rate is charged in between. Average hourly consumption plots for SCMU and the base/intermediate/peak conventional generation costs that inform these rate designs are included in Figure 3-15 and Figure 3-16.

Table 3-4. Time-of-Use (TOU) and Rate-of-Use (ROU) energy costs for base, intermediate, and peak energy. Energy costs were calculated to generate revenue equivalent to the existing demand/energy rate (D/E) structure over the five years of analysis. Resulting rates are similar for TOU and ROU structures at $0.06-0.07/kWh for base energy and $0.013-0.014/kWh for peak energy.

Rate Structure	Equivalent Revenue Rate [$/kWh]		
	Base	Intermediate	Peak
TOU midday (TOUm)	0.063	0.089	0.133
TOU evening (TOUe)	0.066	0.066	0.139
ROU	0.067	0.094	0.141

With the optimal fixed orientation achieving the highest net value of VOS less LAC, the optimal orientation (azimuth, tilt) and annual PV system savings for the different electric rate structures are compared to the benchmark VOS results. Optimal azimuth and tilt angles are shown in Figure 3-7. Demand dependent VOS and D/E systems favor a more southwest facing system at lower PV energy contributions, up to 225° azimuth. Only at the 25% PV energy contribution does the optimal azimuth consistently stay within 10° of south as found in other VOS studies [55]. Time-of-Use (TOU) optimal orientation is nearly constant owing to the time-dependent nature of the rate structure and known temporal position of the sun. The optimal evening (TOUe) azimuth is 10° further west than midday (TOUm). Production data model and TMY results are overall similar and follow the same trends per rate structure. There is not significant tilt variation amongst the design optimizations as all tilts of all systems are between 30 and 40° from horizontal, and somewhat concentrated near the 37° found to maximize total hourly irradiation [54]. However, one interesting observation is that the optimal TMY tilt is consistently 3-5° higher than the corresponding optimal tilt of the production data model.

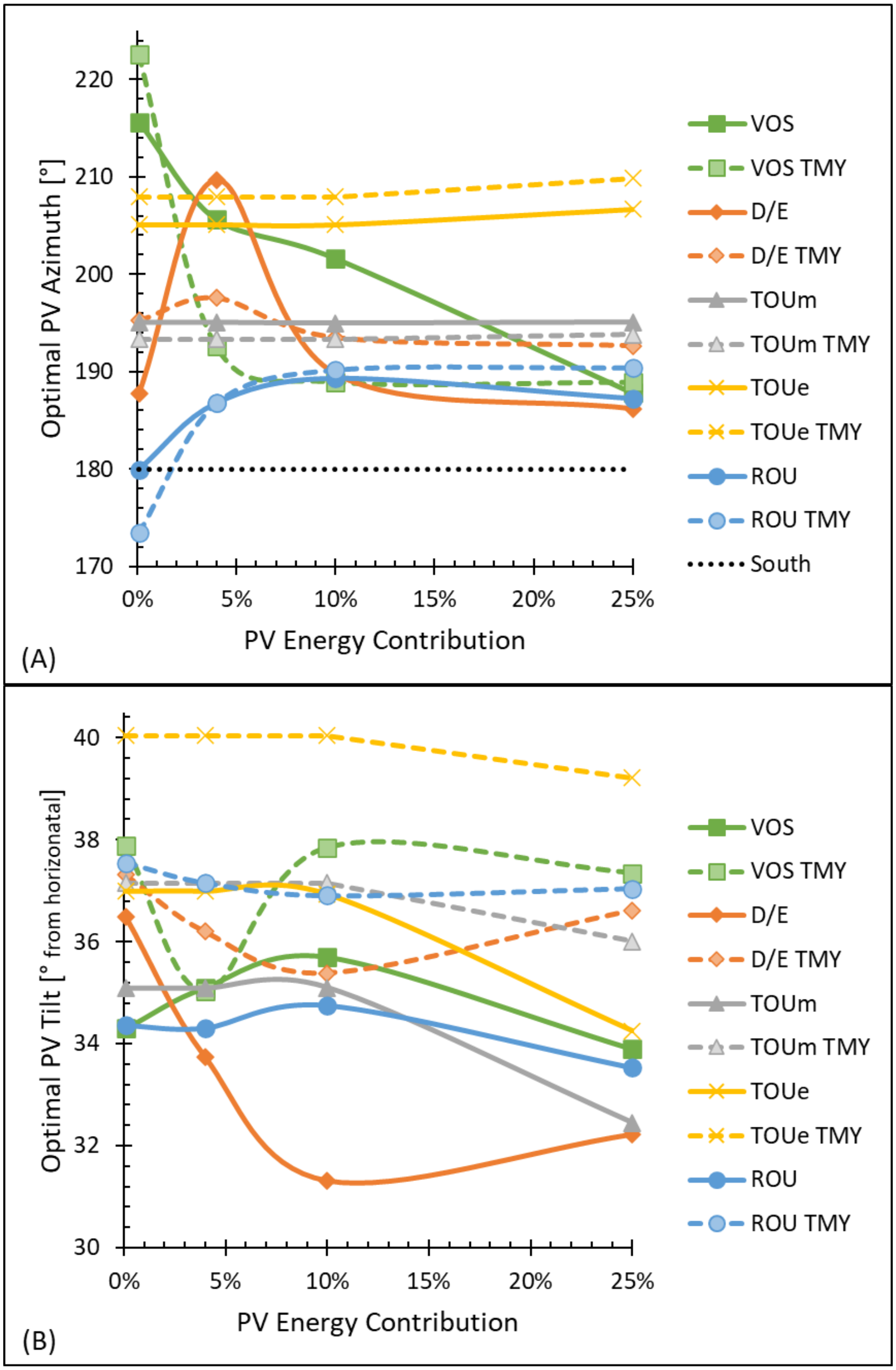


Figure 3-7. Comparison of optimal azimuth (plot A) and tilt (plot B) angles for production data model and Typical Meteorological Year (TMY) for Value of Solar (VOS) as well as demand/energy (D/E), Time-of-Use midday (TOUm), TOU evening (TOUe), and Rate-of-Use (ROU) energy rate structures. With small differences in specific azimuth angles, in general the trends remain the same: VOS and D/E favor a south-southwest facing system with an optimal azimuth that decreases with increasing PV energy contribution, while TOU rate structures maintain a constant optimal azimuth with the TOUe favoring a more southwest direction than TOUm. Tilt is less of an orientation factor than azimuth as all the optimal configurations lie between 30 and 40° tilt. However, there is a consistent trend where the optimal production data tilt is 3-5° less than the corresponding TMY optimization.

Capacity normalized annual cost savings ($/kW) of the optimal fixed orientation PV system are presented in Figure 3-8 for different rate structures. The D/E and ROU savings trend down with increasing PV energy, consistent with observations in VOS. TOU savings stay flat with increasing PV contribution because they are sensitive to the time of energy generation rather than the capacity/rate of energy generation. ROU savings are consistently the highest, while D/E overall agrees best with the VOS benchmark. The extra D/E marginal (0.1%) PV savings can provide some economic incentive to overcome the negative net value for small capacity installations noted in Figure 3-4.

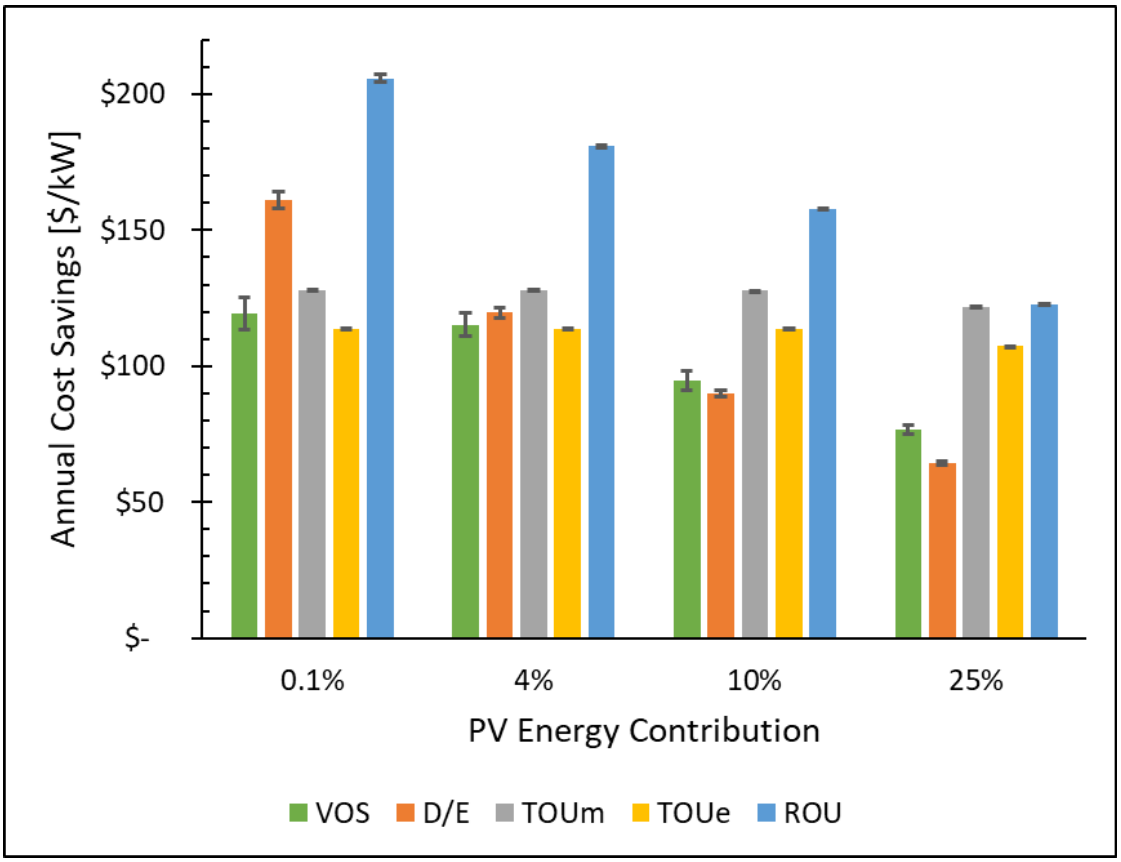


Figure 3-8. Optimal fixed orientation annual cost savings capacity normalized ($/kW) for Demand/Energy (D/E), Time-of-Use midday (TOUm) and evening (TOUe), and Rate-of-Use (ROU) energy structures compared to the Value of Solar (VOS) benchmark. D/E and ROU savings trend down with increasing PV energy similar to VOS, while TOU savings remains flat. ROU savings are consistently the highest. Error bars represent 90% confidence intervals from Monte Carlo simulations.

Plotted uncertainty of the annual cost savings is based upon uncertainty of the production data and production model error. Production model regression curves of the verification and validation data are included in Figure 3-13 and found to be less than 2.3% RMSE of rated capacity and less than 1.2%

error in total annual energy generated (see Table 3-7). The 90% confidence interval error bars on the plots are based on converged Monte Carlo simulations shown in Figure 3-14.

Production data model annual costs savings are compared to the TMY prediction and presented as a difference in Figure 3-9 where positive means the production data model savings are greater. The same 12% difference of VOS identified in Figure 3-5 is also shown Figure 3-9. For this same 4% PV energy contribution case, there is also a 6% advantage of the production data model D/E annual savings. Another large 11% advantage is observed for D/E in the marginal PV energy contribution case. TOU and ROU have small differences in savings in nearly all cases, while D/E maintains a statistically significant advantage through 10% PV energy contribution. For the 25% PV energy contribution case, all rate structures have savings less than TMY which is attributed to increased overproduction.

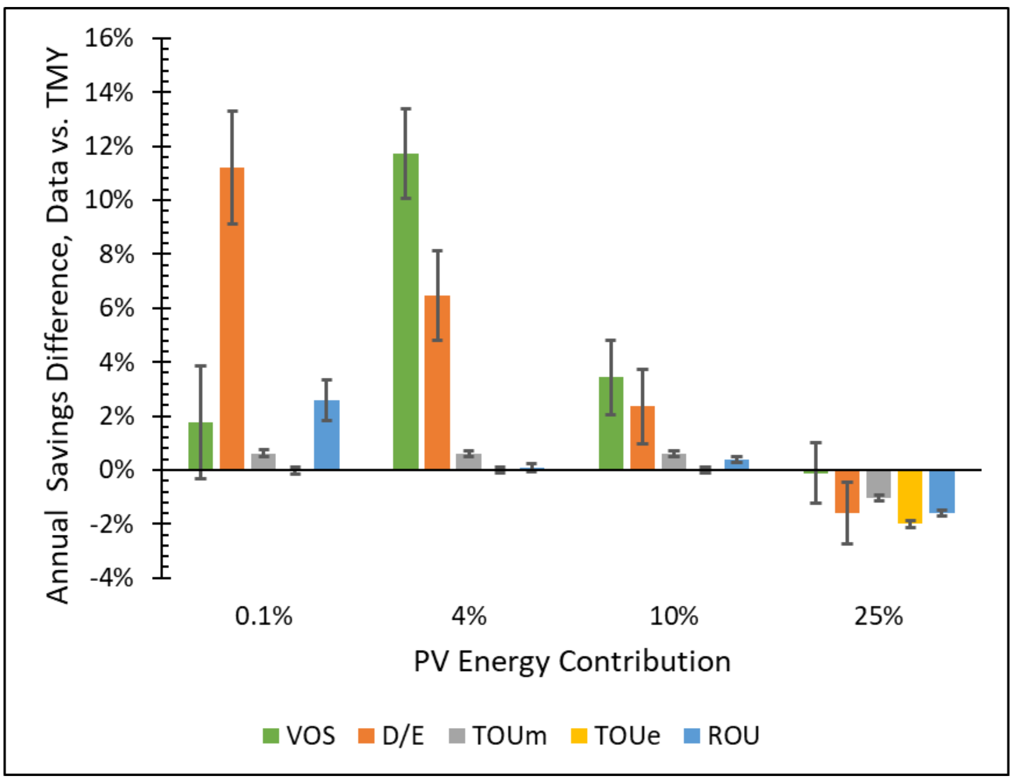


Figure 3-9. Comparison of annual cost savings for the production data model and Typical Meteorological Year (TMY) solar prediction. The 90% confidence interval uncertainty confirms a statistically significant savings difference for Value of Solar (VOS) and demand/energy (D/E), which are most dependent on PV production during specific instances of peak demand. Time-of-Use midday and evening (TOUm, TOUe) show little difference since they are more dependent on total annual energy production which was intentionally equalized. The high 25% PV energy contribution shows a negative difference due to increased PV overproduction as the TMY production tends to be more levelized day-to-day.

3.3.3 Rate Optimization

Since the D/E rate structure was found to best agree with VOS optimization, further investigation was done to customize the D/E rate to better match VOS. To accomplish this, fixed (CAPEX, FOM) and variable (fuel, VOM) costs were separated and compared between VOS, RLDC conventional generation costs, and the existing D/E rate revenue as shown in Figure 3-10. In the figure, the fixed portion of VOS decreases with increasing PV contribution, reflective of the more detailed results in Figure 3-3 and Figure 3-4. The RLDC plot represents the cost of conventional generation using the NG CC and CT assumptions outlined in section 3.2.2. The D/E breakdown is a measure of the fixed demand and variable energy charges for the total revenue of the period of study.

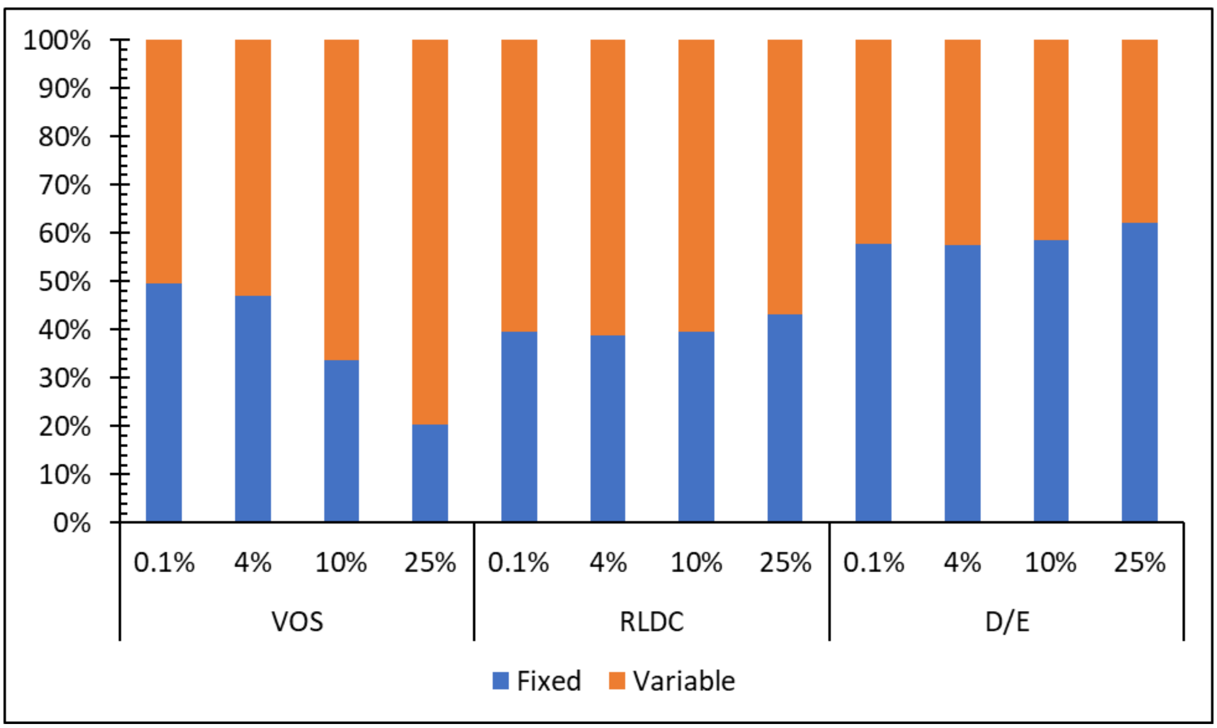


Figure 3-10. Ratio of fixed and variable costs for value for Value-of-Solar (VOS), the Residual Load Duration Curve (RLDC), and demand/energy rate structure. The VOS and RLDC average close to 40% fixed costs while the D/E rate structure is nearly 60% fixed costs.

A key difference that stands out in Figure 3-10 is that the fixed:variable ratio of the RLDC conventional generation cost is 40:60%, while D/E is closer to 60:40%. To investigate the impact of changing the fixed:variable ratio, a new D/E rate structure was defined as shown in Table 3-5. The energy price was set that 60% of LDC revenue would come from energy charges. The monthly demand charges were modified based on the actual peak load for each month and comparable fixed costs for base, mid, and peak conventional generation using the NG CC and CT assumptions outlined in section 3.2.2. The transmission charge was left unchanged. The result is that monthly demand plus transmission costs are clustered much closer together and are reduced from 10-45% depending on the month.

Table 3-5. Comparison of existing demand/energy rate structure to a customized version designed to achieve 40% fixed costs with demand charges adjusted based on actual peak loads and the peak versus base conventional generation fixed costs. The energy charge is increased by 42%, while the monthly demand charge is reduced by 10-45% depending on the month.

Month	Existing		Customized	
	Demand plus Transmission [$/kW]	Energy [$/kWh]	Demand plus Transmission [$/kW]	Energy [$/kWh]
JAN	22.00	0.0315	14.41	0.0447
FEB			14.12	
MAR	16.50		13.83	
APR			13.35	
MAY			14.13	
JUN	27.00		15.16	
JUL			15.56	
AUG			15.14	
SEP	16.50		15.19	
OCT			13.62	
NOV			13.76	
DEC	22.00		13.87	

The customized rate structure was analyzed in the same manner as the other rate structures and compered to VOS and nominal D/E results. Figure 3-11 shows a comparison of optimal azimuth orientation, and Figure 3-12 shows a comparison of the annual cost savings. In both plots, the customized D/E rate is labeled as “WD40E60” meant to indicated is weighted demand structure with 40% fixed and 60% variable revenue generated for the LDC demand conditions.

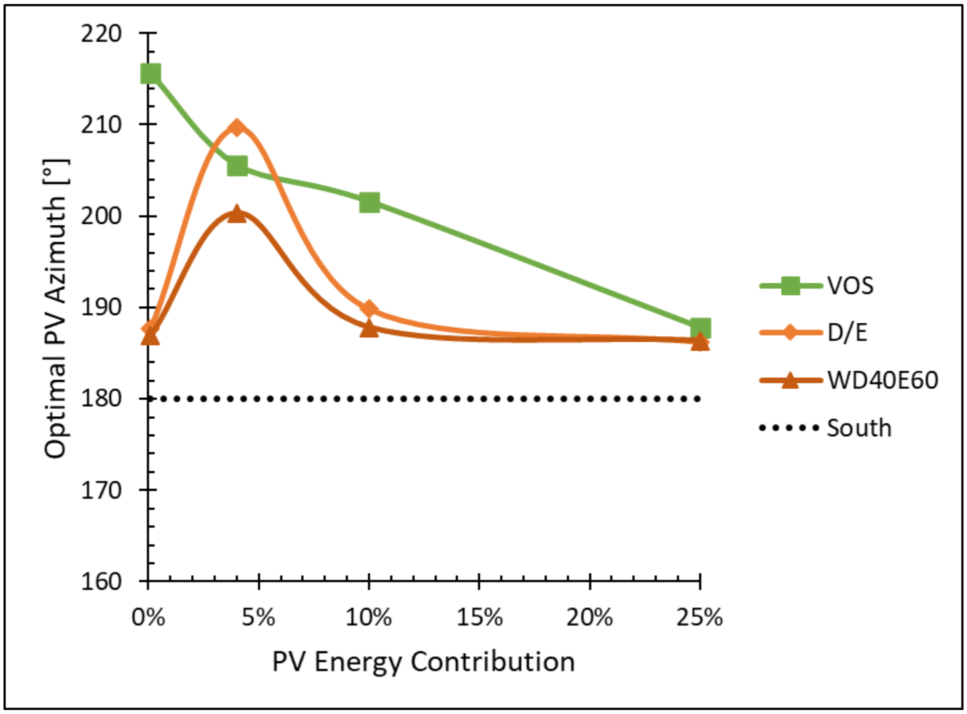


Figure 3-11. Optimal PV azimuth for the 40% fixed, 60% variable weighted demand/energy structure (WD40E60) compared to Value-of-Solar (VOS) and existing demand/energy (D/E). The decreased fixed cost weighting significantly decreased the optimal azimuth for 4% PV energy contribution, but changes other penetrations were not significant.

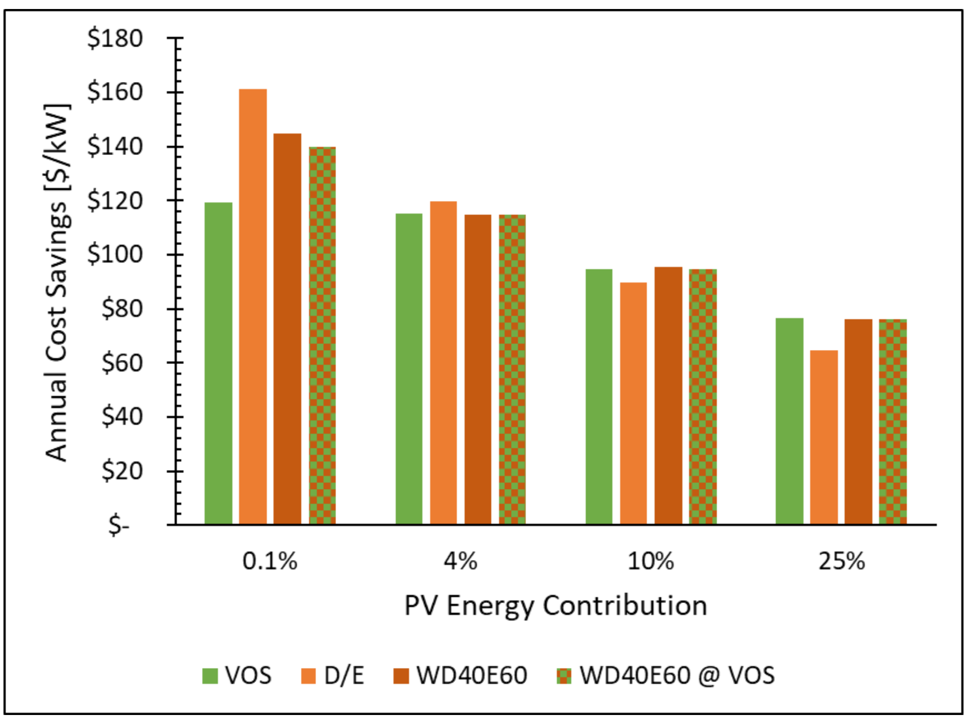


Figure 3-12. Annual cost savings of the 40% fixed, 60% variable weighted demand/energy structure (WD40E60) compared to Value-of-Solar (VOS) and existing demand/energy (D/E). The WD40E60 rate savings best aligns with the VOS benchmark. The WD40E60 @ VOS plot uses the customized D/E rate structure paired with the optimal VOS PV orientation.

In Figure 3-12, the customized D/E rate (WD40E60) does indeed best match VOS, reduced in value compared to the nominal D/E structure in the 0.1% and 4% PV cases, but resulting in higher values for 10% and 25% PV contribution. Since there is large difference in optimal azimuth in Figure 3-11 for the marginal PV contribution case (0.1%), one more analysis in included in Figure 3-12, where the WD40E60 D/E rate structure is paired with the optimal VOS orientation. This does result in a noticeable decrease in the annual cost savings in the marginal case (0.1% PV) where the VOS and D/E optimal azimuth differ by more than 25%. However, in the high PV contribution cases, the difference is hardly noticeable since the optimal azimuth difference is on the order of only 10° or less. Thus, the optimal rate structure as compared to VOS is a D/E scheme with a fixed: variable ratio designed from the RLDC costs of conventional generation.

3.3.4 Investment Analysis

PV investment analysis results are summarized in Table 3-6. The simple payback is shortest for the 4% PV energy case at 13 years, and longest for the 25% PV energy case at 22 years. For the zero NPV analysis, a positive RROE was found for all cases except the 25% PV energy contribution which is slightly negative. The 4% PV case yields a 13% RROE, corresponding to a 7.5% real WACC, indicating installing PV is a sound financial investment. This analysis assumes an overnight install at the optimal PV orientation for each level of PV contribution. It is possible that higher rate-of-returns could be obtained for incremental capacity installations at corresponding optimal PV orientations.

Table 3-6. Investment analysis and rate-of-return for PV investment. A simple payback was calculated based on total PV installation costs and annual cost savings. A zero net present value (NPV) analysis was run to calculate the Rate-of-Return on Equity (RROE) and corresponding Weighted Average Cost of Capital (WACC) over the 25-year period of performance. The 4% PV energy contribution has the shortest simple payback and highest RROE and WACC. The RROE of the 25% PV energy contribution is negative to achieve a zero NPV.

PV Energy Contribution	Simple Payback [yr]	RROE	WACC Nominal	WACC Real
0.1%	16	8%	5.3%	2.7%
4%	13	13%	7.5%	4.9%
10%	16	7%	4.9%	2.5%
25%	22	-2%	1.3%	-1.0%

To provide some comparative context for the simple payback period, a conventional generation payback calculation was performed for natural gas CC and CT generation using the same VOS cost modelling parameters and base, intermediate, and peak capacity factors from the LDC of the municipality. The result is a 4.4-year payback for CC, but more than 47 years for CT despite the higher price of peak electricity. The long CT payback results from the small 0.03 CF of peak generation from the LDC. Details of the calculation are shown in Table 3-8.

From an investment perspective, RROE is highest for the 4% PV energy contribution, which is notable since SCMU's current energy portfolio includes 4% wind energy [98]. Thus, these results indicate that investment in PV makes sense from a financial standpoint in addition to the system energy and capacity value provided by mixed RES generation.

3.4 Conclusions

Value of Solar (VOS) effectively measures the net system benefit provided by PV as total grid energy contribution is increased. VOS is calculated from real PV production data and found to be up to 12% higher than TMY predictions due to higher capacity credit indicative of significant correlation between maximum PV generation and peak utility demand. VOS is calculated for a northwest Iowa municipal utility representative upper Midwest USA geographical and found to exceed the levelized annual costs of installation for low (4%) and medium (10%) PV energy contribution. VOS results like this can be used by decision makers to inform policies regarding PV installation incentives and local electric rates for both consumption and generation.

Leveraging VOS as a benchmarking optimization tool, a demand/energy rate structure is shown to best match VOS in terms of economic value and optimal orientation as PV energy contribution is increased. A 25-year net present value (NPV) economic analysis indicates PV energy is a sound investment up to and beyond a 4% energy contribution that equals the current wind contribution of the utility's energy portfolio. Given the high capacity credit of lower PV energy contribution installations, there is opportunity to meet short term peak demand growth with cleaner PV energy while delaying and/or eliminating the need to build new fossil-based generation plants. As energy storage and other renewable energy enabling technology continues to grow in capability and decrease in cost, adding more PV capacity to the upper Midwest generation portfolio makes good social, environmental, and economic sense.

3.5 Future Work

Future work possibilities exist with PV in SCMU in terms of both physical PV installations and additional modeling. On the modelling side, more data continues to be generated by the Dordt solar lab, and so in a few more years the analysis could be expanded from 5 to 10 years of duration for even greater confidence in the results. Other modelling possibilities include a combined value assessment of wind and solar if co-temporal wind data could be obtained, or a discrete azimuth optimization could be performed where all PV must be oriented due East, South, or West in accordance with the prevailing north-south and east-west grid structure of city streets and buildings.

For actual PV installation, using the VOS results as a guide, appropriate agreements can be made for industrial and residential customers who want to install solar such that they can be fairly compensated for the benefit they bring to the community without being subsidized by customers paying normal rates for all the electricity they use. On a larger scale, MRES began operating a 1 MW PV solar installation in Pierre, SD in 2016 [113], and could be open to the possibility of partnering with SCMU on joint generation venture or large-scale community solar project.   Such PV installations provide a means to bring the value of solar energy specifically to the SCMU community, as well as in general to the upper Midwest region of the United States.

3.6 Supplemental Information

Table 3-7. Annual production (kWh/kW) for installed PV compared to PVWatts Typical Meteorological Year (TMY) prediction. PVWatts DC losses were lowered to 11% from the default 14% to best match the annual production. Also included for comparison to the raw data is the production data model annual production.

Configuration	Data Annual Energy [kWh/kW]	TMY Annual Energy [kWh/kW]	TMY to Data Difference	Production Data Model Annual [kWh/kW]	Model to Data Difference
South, 16° Tilt	1383	1390	+0.5%	1400	+1.2%
South, 29° Tilt	1459	1464	+0.3%	1465	+0.4%
South, 41° Tilt	1476	1479	+0.2%	1475	-0.1%
South, 65° Tilt	1366	1359	-0.5%	1355	-0.8%
One-Axis Tracking	-	1616	-	1571	-

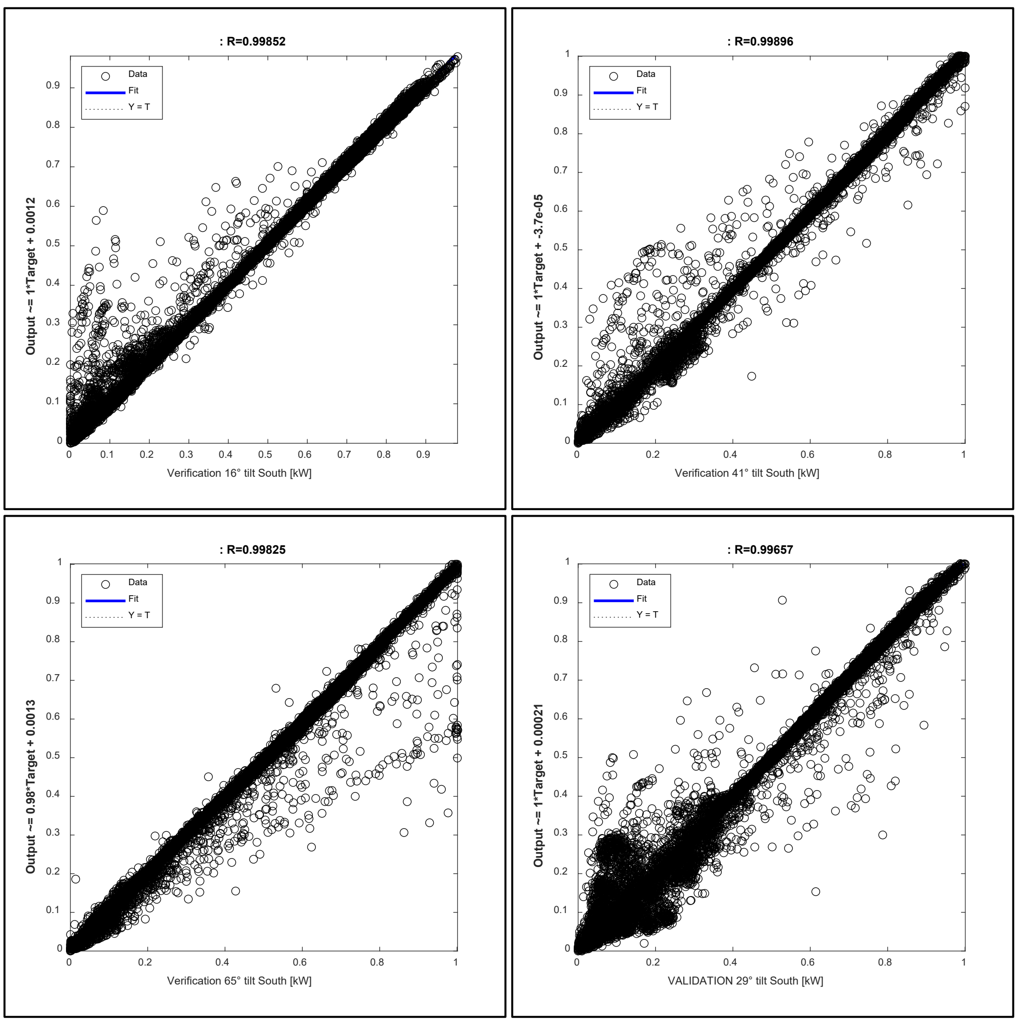


Figure 3-13. Verification and validation regression plots for 16, 29, 41, and 65° tilt, south-facing production data. The production model is calibrated and verified with 16, 41, and 65° tilt data, and then validated with the 29° tilt production data.

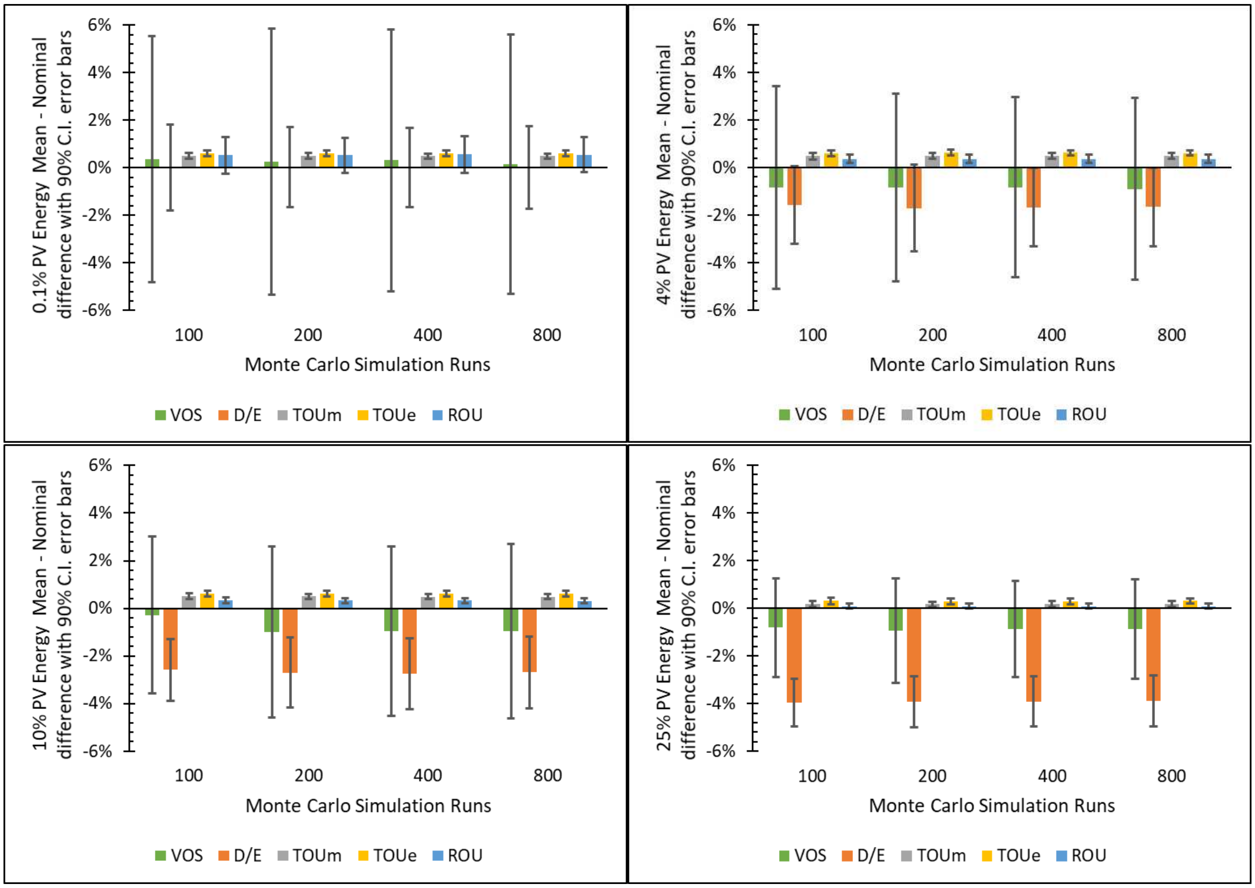


Figure 3-14. Convergence of the Monte-Carlo simulation as runs are increased from 100 to 800 for each of the 0.1, 4, 10, and 25% PV energy contribution scenarios. Results are plotted as percent difference of Monte Carlo simulation mean compared to nominal annual cost savings. Value of Solar (VOS) and Demand/Energy (D/E) rate have a negative bias in simulation savings beyond the 0.1% PV energy marginal scenario, while the Time-of-Use (TOU) and Rate-of-Use (ROU) have slight positive bias. The 90% confidence interval error bars are greater for VOS and D/E rate due to their cost sensitivity to instances of peak demand. The span of VOS and D/E confidence interval also decreases with increased PV energy contribution as a higher portion of total cost savings is attributed to energy than demand.

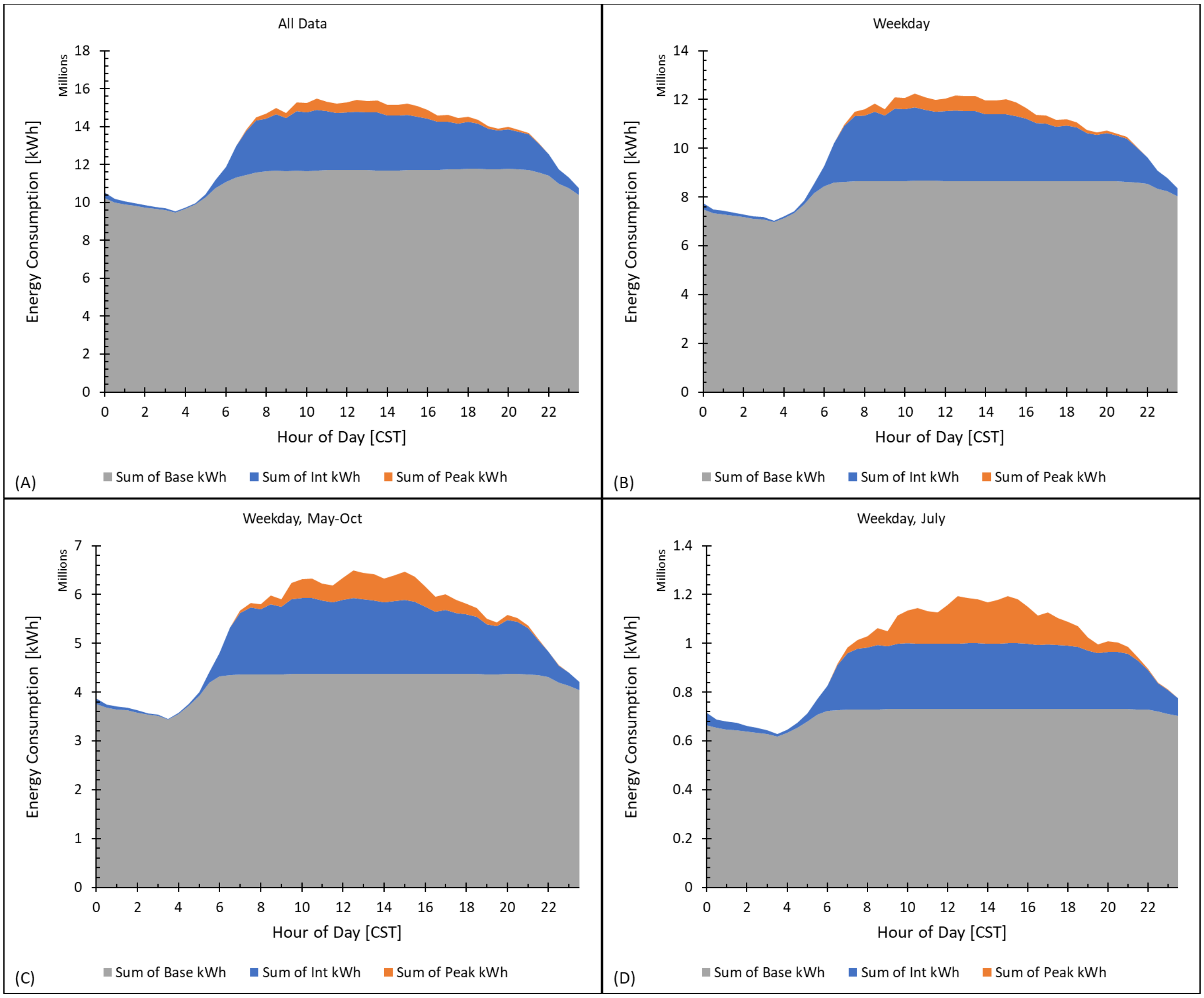


Figure 3-15. Hourly energy consumption broken down into base, intermediate, and peak types from the Load Duration Curve (LDC). Graph A is the entirety of the five years of load data, while graph B shows the increased commercial/industrial load on weekdays. Graphs C and D demonstrate the increased peak demand from late spring to early fall, peaking specifically in July.

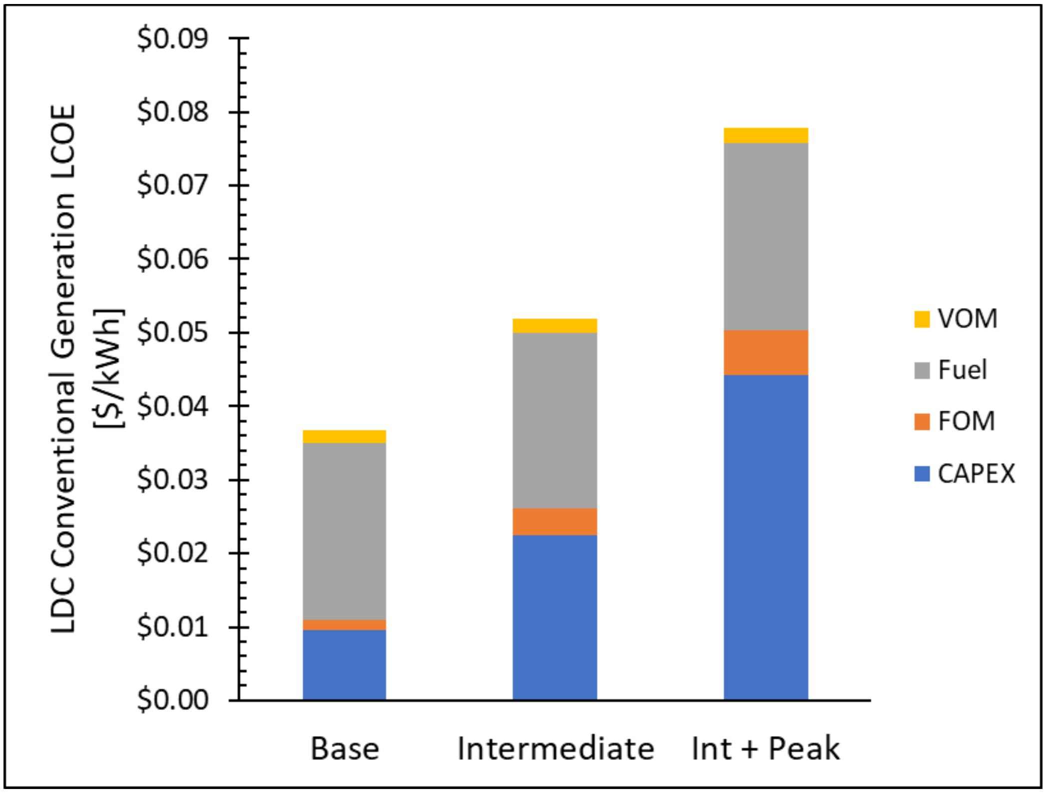


Figure 3-16. Comparative conventional generation Levelized Cost of Energy (LCOE) for base, intermediate, and peak loads based on the Load Duration Curve (LDC). Costs are broken down into categories of capital expenditures (CAPEX), fixed operations and maintenance (FOM), fuel, and variable operations and maintenance (VOM). CAPEX and FOM fixed costs represent an increasing portion of the total cost for intermediate and peak generation. The calculated cost ratios of 1.4 for intermediate to base and 2.1 for intermediate/peak to base agree well with published time-of-use rate structures [111,112].

Table 3-8. Simple payback calculation for combustion turbine (CT) and combined cycle (CC) natural gas conventional electricity generation. The CC capacity factor (CF) values are set based on the combined base and intermediate generation and the CT CF from the peak generation of the baseline load duration curve (LDC) of the municipality (Figure 3-1).

	CT	CC	Source
Overnight Build Cost [$/kW]	$ 713	$ 958	[49]
Transmission Capacity Cost [$/kW]	$ 181	$ 219	[49]
Fixed O&M [$/kW-yr]	$ 7	$ 12	[114]
Variable O&M [$/kWh]	$ 0.0045	$ 0.0019	[114]
Fuel Cost [$/kWh]	$ 0.037	$ 0.024	[3,114]
Electricity Price [$/kWh]	$ 0.14	$ 0.067	Table 3-4
Net Revenue [$/kWh]	$ 0.098	$ 0.041	calculated
Capacity Factor (CF)	0.03	0.77	Figure 3-1
Annual Production [kWh/kW]	263	6745	calculated
Annual Net Revenue [$/kW]	$ 26	$ 278	calculated
Simple Payback [yr]	47	4.4	calculated

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Research Products

Products from the research summarized in this dissertation are listed below.

Peer-reviewed Journal Publications

1. Saarloos, B.A.; Quinn, J.C. Net-Zero Energy Districts and the Grid: An Energy-Economic Feasibility Case-Study of the National Western Center in Denver, CO, USA. *Buildings* 2021, 11, 638. https://doi.org/10.3390/buildings11120638.
2. Saarloos, B.A.; Quinn, J.C. Achieving Optimal Value of Solar: A Municipal Utility Rate Analysis. *Solar* 2022, 2, 99-119. https://doi.org/10.3390/solar2020007.

Peer-reviewed Conference Presentations

1. Saarloos, Benjamin & Jason Quinn, Colorado State University. *A Net-Zero Campus Case-Study: Denver's National Western Center*. ISSST 2020 Conference, July 15, 2020.
2. Saarloos, Benjamin & Jason Quinn, Colorado State University. *Achieving Optimal Value of Solar Through Municipal Utility Rate Design*. ISSST 2021 Conference, June 24, 2021.

List of Abbreviations

ATB	Annual Technology Baseline
CC	Combined Cycle
CF	Capacity Factor
CHP	Combined Heat and Power
COP	Coefficient of Performance
CSU	Colorado State University
CT	Combustion Turbine
DER	Distributed Energy Resource
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERGIS	Eastern Renewable Generation Integration Study
EUI	Energy Use Intensity
FCR	Fixed Charge Rate
FOM	Fixed Operations and Maintenance
GSHP	Ground-Source Heat Pump
HP	Heat Pump
IECC	International Energy Conservation Code
IRR	Internal Rate of Return
ISO	Independent System Operator
LCOE	Levelized Cost of Energy
LDC	Load Duration Curve
MACRS	Modified Accelerated Cost Recovery System
MJ	Mega-Joule
MRES	Missouri River Energy Services
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NWC	National Western Center
NZEB	Net Zero Energy Building
O&M	Operations and Maintenance
PV	Photovoltaic
RES	Renewable Energy System
RLDC	Residual Load Duration Curve
RMSE	Root Mean Square Error
ROU	Rate of Use
RTO	Regional Transmission Organization
SCMU	Sioux Center Municipal Utilities
T&D	Transmission and Distribution
TMY	Typical Meteorological Year
TOU	Time of Use
VOM	Variable Operations and Maintenance
VOR	Value of Resource
VOS	Value of Solar
VSL	Value of Statistical Life
WRC	Water Resources Center
WWSIS	Western Wind and Solar Integration Study
ZEDA	Zero Energy Districts Accelerator