Modelling of Distributed Energy Components and Optimization of Energy Vector Dispatch within Smart Energy Systems

by

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Author’s Declaration

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Abstract

The smart energy system concept provides an integrated framework for the adoption of renewable energy resources and novel energy technologies, such as distributed battery energy storage systems and electric vehicles. In this effort, large-scale transition towards smart energy systems can significantly reduce the environmental emissions of energy production, while leveraging the compatible operation of numerous distributed grid components to improve upon the energy utility, reliability, and flexibility of existing power grids. Most importantly, transitioning from fossil fuels to renewable energy resources provides environmental benefits within both the building and transportation sectors, which must adapt to address both increasing pressure from international climate change-related policy-making, as well as to meet the increasing power demands of future generations.

In the case of building operation, the transition towards future energy systems consequently result in the adoption of decentralized energy networks as well as various distributed energy generation, conversion, and storage technologies. As such, there is significant potential for existing systems to adopt more economic and efficient operating strategies, which may manifest in novel operational modes such as demand-response programs, islanded operation, and optimized energy vector dispatch within local systems. Furthermore, new planning and design considerations can provide economic, environmental, and energy efficiency benefits. While these potential benefits have been justified in existing literature, there is still a strong research need to quantify the impacts of optimal building operation within these criteria, under a smart energy system context.

Meanwhile, the transportation sector may benefit from the smart energy network concept by leveraging electric mobility technologies and by transitioning vehicle charging demand onto the grid's electricity network. In this transition, the emissions associated with fossil fuel consumption are displaced by grid-generated electricity, much of which may be derived from zero-emission resources in systems containing high renewable generation capacities. While small electric vehicle fleets have currently been successfully integrated into the grid, higher market penetration rates of electric vehicles demand significantly more charging infrastructure. In consideration of the consequences of various electric vehicle charging modes resulting from large-scale mobility electrification, there is a gap in the literature for the planning and design of charging infrastructure for facilitating interactions between electric vehicle fleets and future smart energy network systems.

Within the work presented in this thesis, quantitative analysis has been presented for the potential for optimal building operation between complementary commercial and residential building types. From this, the economic and environmental benefits of applying the principles of smart energy systems within mixed residential and commercial hubs have been evaluated at reductions of 61.2% and 1.29%, respectively, under the context of an Ontario, Canada case study. Furthermore, reduced installation of local energy storage systems and consumption of grid-derived electricity were reduced by 6.7% and 13.8%, respectively, in comparison against base case scenarios in which buildings were operated independent of the proposed microgrid configuration. Meanwhile, the investigative work for the role of charging infrastructure in electric vehicle integration within smart energy systems provided insight into the power flow characteristics required to facilitate advanced electric vehicle charging modes. Most importantly, the work demonstrated limitations to the controlled/smart charging and the vehicle-to-grid charging modes imposed by charging port availability, electric vehicle plug-in durations, and maximum power flow characteristics. These results have highlighted the need for charging infrastructure to emulate the availability and fast response characteristics of stationary energy storage systems for successful vehicle-to-grid implementation, as well as the need for maximum power flow limitations for charging infrastructure to be well above the current level 2 standard for home- and workplace-charging.

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Nomenclature

The following abbreviations and symbols are used in this manuscript:

BESS	Battery energy storage system
CHP	Cogeneration of heat and power
DER	Distributed energy resource
DHW	Domestic hot water
DR	Demand response
ESS	Energy storage system
EV	Electric vehicle
FIT	Feed-in-tariff
GHG	Greenhouse gas
HVAC	Heating, ventilation, and air conditioning
ICEV	Internal combustion engine vehicle
MIP	Mixed-integer problem
PV	Photovoltaic
RES	Renewable energy resource
SOC	State-of-charge
TOU	Time-of-use
V2G	Vehicle-to-grid

Variables

i	Index for inflow energy vector set
j	Index for energy demand load set
k	Index for energy storage technologies
t	Index for time
C_{ij}	Coupling matrix
$Cost_{op}$	Annual operating costs of the system
$Cost_{fuel}$	Annual fuel costs of the system

$D_i(t)$	Energy vector demands of the energy hub
$\varepsilon_{k,in}$	Energy vector inflow efficiency for energy storage system
$\varepsilon_{k,out}$	Energy vector outflow efficiency for energy storage system
$\varepsilon_{PEV,charge}$	Charge efficiency for the EV fleet
$\varepsilon_{PEV,discharge}$	Discharge efficiency for the EV fleet
$E_{max,k}$	Maximum storage capacity of storage system
$E_{PEV,loss}(t)$	Loss of stored electricity due to driving for the EV fleet
$F_j(t)$	Energy vector feeds into the energy hub
$F_{j,max}$	Maximum flow capacity for the feed energy vector
$F_{j,min}$	Minimum flow capacity for the feed energy vector
$Q_{k,in}(t)$	Inflow of energy vector into the energy storage system
$Q_{k,in,max}$	Maximum inflow rate of energy vectors into energy storage system
$Q_{k,in,min}$	Minimum inflow rate of energy vectors into energy storage system
$Q_{k,out}(t)$	Outflow of energy vector into the energy storage system
$Q_{k,out,max}$	Maximum outflow rate of energy vectors into energy storage system
$Q_{k,out,min}$	Minimum outflow rate of energy vectors into energy storage system
$Q_{k,stor}(t)$	Net energy vector flow into energy storage system
$Q_{PEV,charge}(t)$	Power charged to the EV fleet
$Q_{PEV,discharge}(t)$	Power discharged from the EV fleet
$Q_{PEV,stor}(t)$	Net flow of electricity into the EV fleet
$SoC_k(t)$	State-of-charge of storage system
$SoC_{k,max}$	Maximum charge capacity of the storage system
$SoC_{k,min}$	Minimum charge capacity of the storage system
Z	Overall objective function

Chapter 1 Introduction

1.1 Challenges and Motivation

With respect to the current state of the energy industry, worldwide energy use is highly dependent on the consumption of nonrenewable fossil fuel resources. Moreover, the majority of energy is consumed by buildings and by the transportation sector, which have been projected to increase due to growing populations and increasing energy demands. Simultaneously, while under pressure from the environmental impacts of unsustainable energy generation practices and facing the impending depletion of fossil fuel resources, the energy industry must adapt to tackle these challenges without compromises to the environment or to its ability to meet future energy needs.

Meanwhile, development and commercialization of novel technologies presents additional challenges to the energy industry in consideration of their integration into the existing centralized power generation framework. In particular, renewable resources such as solar- and wind-based technologies cannot be easily integrated as large-scale centralized generation stations, which requires the power grid to adapt to accommodate distributed generation resources. Such resources also exhibit intermittency based on weather conditions. They are thus more difficult to control and require accurate forecasting for their power generation potential. Additionally, recent transition towards mobility electrification may displace a large portion of existing internal combustion engine vehicle fleet with electric vehicles (EV), which redirects a significant volume of refueling demand onto the power grid. These novel technologies introduce further complications to the energy industry, which must then account for uncontrollable, intermittent generation resources as well as increased volatility in energy demand behavior from end-users.

In short, the main challenges to the energy industry are as follows:

1. Growing energy demands require the expansion of existing power generation capacity;
2. Depletion of fossil fuel resources require the transition towards renewable or sustainable energy resources;
3. Emergence of novel energy technologies requires the grid to have improved operational control and to become robust to the integration of future energy technologies.

The traditional centralized power generation framework is challenged because it needs to adapt to the integration of significant amounts of renewable and sustainable energy resources, while ensuring energy security against the potential high volatility of future energy demands. This has spurred the transition of the centralized power generation model towards distributed generation frameworks, which has led to the conceptualization of smart energy systems [1].

Under this concept, the challenges faced by the traditional power grid may be addressed via optimized energy vector dispatch and coordinated control of grid components, which is accomplished through the implementation of advanced communication technologies and information networks. As such, a smart energy system has the potential to yield improved utilization of grid components, decreased line losses, and increased resiliency against energy outage events [2]. Moreover, the smart energy system concept accommodates the integration of distributed grid energy components, which includes renewable energy resources (RES) as well as novel technologies such as EVs, with the additional potential to absorb future energy technologies.

1.2 Objectives

The primary objectives of this work are to investigate the potential of the smart energy system concept for more efficient energy vector dispatch within buildings and to evaluate potential challenges for EV integration into future smart energy systems as a distributed energy resource. More specifically, this thesis work aims to advance the literature through the following contributions:

1. Quantification of the energy, emissions, and economic impacts of complementary building operation within a 'smart energy system' context;
2. Development of a simulation framework for the optimization of energy hub operation in consideration of projected building energy demands and stochastic EV charging demands;
3. Evaluation of the role of charging infrastructure in presenting potential challenges for EV integration into smart energy systems as distributed energy technology components.

Based on these contributions, this thesis will present the methodology applied to achieve each objective, as well as the results and the relevant implications of this work.

1.3 Thesis outline

This thesis consists of 5 chapters. In the present Chapter, the main research problem and motivation for its solution are presented, followed by a description of the research objectives of this thesis. In Chapter 2, the background for the topic area is provided along with a review of the existing literature in order to provide a survey of the landscape of the field. Following this, two research works are presented. First, Chapter 3 presents a quantitative work that examines the potential benefits of complementary building operation within microgrids, which are evaluated using energy efficiency, emissions, and economic criteria. Next, Chapter 4 presents an investigative modelling study focused on evaluating the impacts of charging infrastructure on the integration of electric mobility into smart energy systems. Lastly, Chapter 5 concludes this thesis with a summary of the presented research works and recommendations for future developments.

Chapter 2 Background and Literature Review

2.1 Background: The Energy Project

The majority of the world's energy use is currently reliant on the consumption of nonrenewable energy resources. Primarily, fossil fuel consumption in the energy generation and transportation sectors contribute to significant amounts of greenhouse gas emissions, which has noticeably accelerated the effects of climate change.

In response to unsustainable practices in resource consumption, international collaboration and policy-making have placed pressure onto the power generation industry to transition towards renewable energy resources (RES), especially intermittent solar and wind generation. In addition, there is increasing awareness of the need to adopt more sustainable practices for energy use. In consideration of the main end-uses of energy, there is significant potential for improvement in energy consumption practices within buildings and for transportation purposes, since these two end-uses accounts for approximately 60% of the total energy use worldwide [85].

Motivated by the pressure to advance towards more sustainable energy practices, developments in industry have led to the commercialization of various novel distributed energy technologies. Examples include solar- and wind-based generation technologies, as well as electric vehicles (EVs). Adoption of such technologies into the existing power grid, however, poses additional challenges due to the volatile energy generation and consumption behaviors they exhibit. As such, there is a strong research need to determine optimal planning, implementation, and operational strategies with respect to the future of the power grid and how it should regulate and interact with disruptive energy resources and technologies.

2.1.1 Existing Power Production Practices and the Primary Energy resource

Currently, the majority of energy production worldwide adheres to a centralized power generation framework, in which the energy demands of a network is met using a number of centralized, large-scale power generation plants. The generated power is delivered via transmission and distribution, which generally consists of high voltage alternating-current transmission networks for long-distance delivery of electricity and a series of step-down voltage transformers for distribution at the local level to end-users. Meanwhile, the network relies on back-up and reserve generators to regulate power production in order to match the overall energy consumption needs of the network.

As of the writing of this thesis, the resource mix for power generation is composed primarily of fossil fuels, with a small portion being produced by renewable resources. Similarly, the primary energy resources used in the transportation sector are also composed mostly of fossil-fuel resources.

2.1.2 Emergence of Renewable and Distributed Power Generation Technologies

While the current mix of energy resources satisfy the world's energy consumption needs, recent attention towards the environmental impacts of such practices have led to a worldwide agenda aimed at shifting towards a more sustainable energy future. As a result, developments in and pressure to adopt renewable and alternative energy generation technologies have improved the commercial feasibility of several distributed RES. In particular, wind- and solar-based generation technologies have been favored for their potential for zero-emission power generation. In agreement with the benefits and deploy-ability of these technologies, major efforts are being made worldwide to accelerate their integration into power grids. Several highlights of this point are the policies set by California, US to achieve 33% RES integration by 2020 [3], Germany's target of 65% RES integration by 2030 [4], and Denmark's goals of achieving 100% RES integration by 2035 [5].

Despite their popularization, transition towards an energy mix with significant adoption of RES faces several hurdles. Mainly, the intermittent nature of RES severely limits the flexibility of such resources for addressing immediate consumption demands. Several approaches are available for resolving this weakness to RES integration, such as energy storage systems (ESS), demand-side management strategies, or collaborative energy import/export markets. For the purposes of this thesis, only the use of ESS are considered due to the context of the works presented. However, a comprehensive review of the state of the literature on RES integration is available in [6] by Martinot. Additional hurdles to RES integration include high capital costs, installation of supporting power conditioning infrastructure, and impacts on electricity prices. These challenges are outlined in more detail in [7] by Stram.

Other distributed power generation technologies are also feasible for deployment into smart energy systems. Particularly for this thesis, small-scale co-generation technologies have been considered for deployment in local systems.

2.1.3 Transition Towards Electric Mobility

Concurrent to the transition towards renewable and sustainable technologies for energy generation, recent trends towards mobility electrification have sparked the possibility of large-scale penetration of EVs into the automotive market. In comparison to conventional internal combustion engine vehicles (ICEV), EVs are reliant on grid-generated electricity for fuel. Within power grids with sustainable resource mixes, EVs have the potential to operate more efficiently than ICEVs and with a significant reduction in emission production, since their operation would be derived from electricity generated through renewable and sustainable resources.

Similar to the efforts made to accelerate the adoption of RES, support initiatives have been set by various countries to support the deployment of EV fleets and to encourage transition towards major mobility electrification. Most notably, the zero-emission vehicle mandate originating from California, US has been adopted in a number of US states to accelerate EV market penetration. A similar initiative has been implemented in China as a part of its 13th Five Year Plan, as evidence of the government's aim to encourage electric mobility as the future of the transportation sector.

2.1.4 Challenges to the Power Grid

In consideration of the current state of energy consumption and generation practices, the pressure to transition towards a more sustainable energy future, the popularization of various novel energy resources and technologies, as well as the operational and implementation-related complications associated with these technologies, the existing centralized power grid framework must adapt to tackle a number of challenges. A detailed description of these challenges may be found in [8] and are summarized as follows:

- Expanding base load generation capacity in anticipation of increasing energy demand;
- Transitioning towards renewable energy mix to mitigate future climate change impacts;
- Improving adaptability to novel technologies to retain grid reliability;
- Increasing resiliency against line and generator failures for improved energy security;
- Reduce line losses for improved energy efficiency;
- Implementing improved communication and information technology and optimal operating strategies for more efficient energy vector dispatch;

- Becoming more cost-competitive to increase grid development and energy availability.

While there are numerous approaches to addressing these challenges, most on-going energy system development plans incorporate the following strategies [9]:

- Expansion of distributed renewable and sustainable energy resources and transition away from fossil fuel resources;
- Mitigating volatile and variable energy behaviors via energy storage implementation;
- Reduction of future energy demands through demand-side management programs;
- Implementing increased connectivity in network topologies for increased energy security;
- Planning of distributed grid component installation to reduce line losses and to address energy consumption needs of local systems;
- Adopting advanced information and communication technologies and optimal energy vector dispatch strategies for increased energy utility.

2.1.5 The Concept of Smart Energy Systems

In order to effectively address the future needs of the power grid and to establish a robust and flexible grid system, an integrated solution has been proposed under the concept of smart energy systems. Within this concept, the existing power grid framework is proposed to transition towards a decentralized network model, which leverages advancements in communication and information technology to integrate a variety of energy vectors, distributed energy resources, grid components, as well as novel energy technologies. Such a configuration is expected to improve upon the operational efficiency of the conventional power grid and increase the resiliency of the network to disruptive technologies, highly volatile power generation and consumption behavior, and unplanned power outage events.

A detailed overview of the smart energy system concept and review of the literature on its conceptualization is provided by Lund et al. in [1]. With respect to their implementation, smart energy systems may be realized through the large-scale adoption of distributed energy generation, storage, and conversion technologies, of effective communication and information technologies, as well as of economic and policy-related frameworks to support the coordinated operation of these technologies.

2.2 Smart Energy Systems

The adoption and integration of novel energy technologies have led to the conceptualization of smart energy systems as an overarching framework for future energy networks. A detailed discussion and overview of this emerging concept may be found in [1] as provided by Lund et al. In principle, the concept is characterized by cooperation between novel energy and communication technologies. In practice, however, the concept has yet to manifest within a real, large-scale system. As such, it may be best to begin the discussion on smart energy systems through a consideration of its key components and operational characteristics.

2.2.1 Distributed Energy Resources

One of the key characteristics of smart energy systems is its compatibility with distributed energy resources (DER). In contrast to the role of large-scale power generation stations in the centralized power generation framework, DERs may be implemented as small-scale power generation grid components. In this way, generation capacities may be installed closer to end-users, which has operational advantages in reducing line losses from power transmission, increased energy security for the local system, and decentralizing the operational controls for the energy network. Currently, the technologies generally favored for their deploy-ability in literature are solar- and wind-based technologies, as well as micro co-generation technology [10].

In terms of solar- and wind-based generation technologies, their viability have been demonstrated in a number of studies. In [11] Jamil et al. present the potential for more effective planning and adoption of solar PV generators as distributed grid components, highlighting the characteristics of solar PV technology as distributed generation resources. Whereas in [12], Richardson et al. consider several scenarios of RES integration with supporting demand response and energy storage technologies, under an Ontario, Canada context. Again, the conclusions of the article highlight the technical feasibility of RES integration within current power grids. However, it is also clear that effective RES integration relies heavily upon supporting technologies. This last point has been similarly made in other works such as in [13] by Hill et al. and in [14] by Hassan et al. As a general consensus in literature, it is apparent that the success of large-scale RES integration is tied to the availability of supporting infrastructure and technologies to regulate intermittency.

The feasibility of micro-combined heat and power (CHP) technology for deployment in smart energy systems have been similarly focused on in several demonstration studies. For example, Biglia et al. present in [15] a case study of micro-CHP implementation within an Italy context. The conclusions of the study emphasize the dependence of micro-CHP technology on the availability of natural gas, which point to its weak economic and environmental feasibility in energy networks with high RES integration. In contrast, more positive results have been derived from case studies under different contexts, such as in [16], in which Fuentes-Cortes et al. conclude on the economic and efficiency advantages of micro-CHP over conventional power generation technologies in a Mexico context. Further elaborating on this discrepancy, a discussion of the conditions for evaluating the feasibility of micro-CHP technology is provided in [17] by Comodi et al. The article notes that the viability of micro-CHP is dependent on the availability and economics of fuel resources as well as on the resource mix of the energy system. This suggests that micro-CHP should be considered for energy systems with an existing resource mix containing high portions of fossil fuels, which are also subject to comparatively high costs for the adoption of alternative energy resources.

2.2.2 Distributed Energy Storage Capacity

Smart energy systems may also implement grid energy storage components to regulate imbalances between generation and consumption behaviors. Particularly to address the intermittent nature of RES, energy storage components contribute necessary capabilities such as load-balancing, back-up generation, and ancillary services. Furthermore, a variety of energy storage technologies are available and their scope encompasses a wide range of operating characteristics. As such, selection and implementation of storage capacities vary depending on the properties of the energy system as well as on the operational requirements of the storage technology. A review of the characteristics of existing and developing energy storage technologies may be found in [18], as compiled by Aneke et al., with a particular focus on energy storage for secondary forms of energy such as heat and electricity.

Of particular relevance to the content of this thesis is the deploy-ability of battery energy storage systems (BESS), which is currently the most widespread energy storage technology with respect to power grid applications. BESS technology has been considered in a number of studies for their role in supporting RES integration and in providing ancillary services, such as in [19] by Barelli et al. and in [20] by Branco et al. In both studies, the incorporation of BESS technology into energy systems have been demonstrated to provide improved energy utilization of RES components as well as more economic operation of the energy system at the local level.

2.2.3 Optimal Energy Vector Dispatch

In consideration of the operational aspects of the smart energy system concept, energy vector dispatch strategies are often proposed to optimize economic, energy efficiency, and energy utility criteria. Here, energy vectors are used to encompass all forms of energy flows such as electricity, heat, hydrogen, and natural gas. Overall, appropriate implementation of such strategies result in reduced environmental emissions, lower operating costs to the energy network and to end-users, and increased resiliency of the network against failure.

This is an extension of the optimal power flow problem (OPF) for traditional electricity grids, for which a review of the existing literature is provided in [21] by Capitanescu et al. As emphasized upon in the article, growing integration of renewable generation and increasing need for flexible grid operation requires an adaptation of the OPF for smart energy systems. Particularly, interactions between different energy vectors and grid components within smart energy systems provide additional degrees of freedom in the coordination of energy vector flows. This aspect of smart energy systems has already been incorporated into a number of studies of multi-energy vector systems. As an example, in [22], Ma et al. model an energy system with integrated electricity, cooling, and heating networks to leverage the interactions between renewable generation, co-generation, and ESS. Based on evaluation of several case studies, the presented work demonstrates the potential for more efficient and economic operation of energy systems through the coordinated operation of multiple energy vector systems.

2.2.4 Energy Hubs, Microgrids, and Virtual Power Plants

With respect to the potential of smart energy systems to facilitate optimal operation of its grid components, several concepts have emerged in literature to encapsulate key operational characteristics of smart energy systems. One of these concepts, energy hubs, targets the potential for optimal energy vector dispatch and for effective planning and implementation of grid components for flexibility and reliability. In this effort, the foundational mathematical model for energy hub modeling has been proposed by Geidl et al. in [23]. The model has been adapted in a number of studies to explore energy hub systems integrating various combinations of energy technologies under different economic, environmental, and system contexts. For example, Vahid-Pakdel et al. presents an adaptation of the model in [24] to examine a complex multi-carrier energy hub system incorporating distributed wind-based power generation, district heating network, demand response programs, and both thermal and electrical energy markets. Another example may be found in [25], in which Evins et al. introduced improvements to the model to more accurately model realistic behaviors and characteristics of energy systems.

Another concept often discussed in literature is that of microgrids, which focuses on the potential for islanded or isolated operation of local systems within the grid. Such islanded operation aims to secure energy reliability for the local system and may be leveraged to provide alternative financial options for the system in terms of satisfying its energy needs. This feature of microgrids has been studied in [26] by Wang et al. in consideration of energy systems with networked microgrids. Moreover, the microgrid concept also promotes the cooperation of end-users at the local level to improve energy utilization and reliability. In both [27] and [28], Bandara et al. and Soltowski et al. respectively study the integration of distributed solar-based power generation under a microgrid context. While the work in [27] mainly focused on the feasibility of DC microgrids for RES integration, both studies agree on the role of the microgrid concept for facilitating improved utilization of renewable generation capacities.

Lastly, virtual power plants are generally presented as a framework for aggregating DER to enable centralized, coordinated control of grid resources. While this concept is not considered in significant detail within the works presented in this thesis, a review on the subject may be found in [29] as compiled by Lv et al.

2.3 Mobility Electrification and Integration of EVs into Smart Energy Systems

In consideration of the magnitude of energy consumed for transportation worldwide and the corresponding environmental impact, recent market trends toward mobility electrification provides an opportunity to significantly alleviate the environmental burden of the world’s transportation-related energy consumption. Through the transition from conventional fossil-fuel based internal combustion engine vehicles to EVs, the transportation sector may shift from fossil fuels as the primary fuel to grid-derived electricity as its main energy resource. This is complemented by trends in the energy generation industry to increase renewable distributed energy resource capacities. In the most optimal scenario, high market penetration of EVs and increasing adoption of renewable and sustainable distributed energy resources can significantly reduce the rate of emission generation resulting from vehicle operation. Meanwhile, systems retaining nonrenewable energy resources in their grid mix may be able to leverage economies of scale and meet the energy demands for transportation more efficiently through power plants with operating efficiencies greater than that of the internal combustion engines used within vehicles.

In this transition, however, mobility electrification shifts a substantial amount of energy demand onto the power grid. This poses infrastructural and technological challenges, since the power grid must adopt a more robust and reliable transmission and distribution system to facilitate the increase in power flows, as well as to provide high power quality while accurately predicting consumption demand to coordinate available generation capacities. The matter is further complicated by market, social, and political factors, such as the unpredictability of the EV market, the social obstacles to adopting vehicles as a grid component, and the various policy considerations surrounding EVs. Despite these challenges, there is strong research incentive to optimally integrate EVs into the power grid. While the primary motivation is the emission reduction potential of mobility electrification, EVs have also been considered for their potential to provide high-value services to the grid, such as peak shaving, reactive power support, back-up power, and support for RES integration.

Currently, the literature discusses the integration of EV technology into the power grid in three scenarios. In the first case, EV fleets may be expected to behave as fixed loads and participate in uncontrolled charging behavior, which will impose highly volatile and variable charging demands onto the power grid. In the second case, implementation of communication technology and control strategies for unidirectional power flow to EV fleets allows them to be integrated into the grid as flexible loads. Lastly, implementation of the vehicle-to-grid (V2G) concept integrates EV fleets into the power grid as distributed energy resources in the form of mobile BESS. In the following review, the literature on these three operational modes will be discussed in detail, along with an examination of the major challenges to EV implementation into the smart energy system concept.

2.3.1 Uncontrolled Charging Impacts

In comparison to conventional internal combustion engine vehicles, the refueling needs of EVs are satisfied via power draws from the electrical grid. As such, a significant amount of energy consumption demand may be shifted onto the power grid as the vehicle market transitions towards electric mobility. A major complication introduced by this shift, however, is the magnitude and volatility of the charging behavior of large EV fleets. In particular, uncontrolled charging behaviors from such fleets introduce a high degree of unpredictability to the overall consumption demand experienced by the power grid, as these behaviors are inherently difficult to forecast. A high degree of uncontrolled charging may also require a large reserve generation capacity for power regulation. Even in the most optimistic scenario, a certain degree of uncontrolled EV charging will occur to address unique driving needs, such as emergency on-road charging, irregular trip schedules, and inadequate driving ranges in EVs.

Considering the integration of EVs into the power grid as fixed loads exhibiting uncontrolled charging behavior, large EV fleets have been projected to place significant strain onto the power grid. This manifests as an increase in both the overall consumption demand as well as the peaking demand experienced by the power grid. Moreover, the combined effects of uncontrolled EV fleet charging behaviors and the intermittency of distributed energy resources will significantly reduce the reliability and flexibility of the power grid, which may ultimately need to rely on vast fossil-fuel based reserve generation capacities to reliably sustain the operation of the power grid.

In order to evaluate the relevance of the impact of large-scale EV adoption, several works have been presented in the literature to quantify the potential impacts of uncontrolled EV charging behavior under the contexts of various EV market penetration scenarios. In [30], Clement et al. presents a forecasting study on the impacts of uncontrolled charging behaviors of EVs at the residential level. The study is based upon historic data of EV charging behaviors and employs stochastic programming to account for uncertainties. The results indicate that uncontrolled charging behaviors significantly increase peaking power demand on the grid and also introduces increased power losses and decreases in power quality. In contrast, an alternate scenario implementing controlled charging strategies have been shown to suppress the effects of EV fleets on peak power consumption, power losses, and power quality of the grid comparable to the performance of the grid without EV adoption. Similarly in [31], Darabi et al. forecast uncontrolled EV charging profiles based on national household travel survey (NHTS) data. The study considers a large dataset and models potential EV fleet behavior based on existing vehicle use practices. Again, the results indicate significant increases in peaking power demand due to EV charging as well as the effect of maximal power draw limitations on the peaking behavior. Furthermore, the authors propose several policies to regulate charging behavior via power flow limitations, scheduling, and electricity pricing strategies, which gravitate towards controlled charging strategies.

Additional studies have been conducted to evaluate potential impact scenarios considering the contexts of different power grids and at various degrees of market penetration of EVs, such as in [32] for Canada and in [33] for the US. As a shared conclusion of these studies, the consensus is that reasonable degrees of adoption of EVs into the automotive market introduces the impacts of uncontrolled charging as a significant concern for the power grid at the distribution level. As such, effective policy and control strategies must be implemented to control EV charging, or otherwise regulate their impact to minimally affect the reliability and flexibility of the grid.

2.3.2 Controlled Charging Strategies

Given the potential impacts of uncontrolled EV charging, several strategies have been considered to manage and regulate EV charging demands to preserve the reliable operation of the power grid. In one approach, controlled or smart charging strategies have been proposed as a means for regulating the charging demands of EV fleets. In this charging mode, EVs with non-immediate charging needs may be managed in aggregate as a flexible load, such as when EV fleets engage in home or workplace charging. Thus, their charging demands become predictable and may be leveraged to complement the operation of the power grid. Additional benefits of this operational mode are its abilities to support the integration of renewable generation capacities, to reduce the variability of the power grid, and in providing economic and environmental advantages over the uncontrolled charging mode.

In previous research works, efforts have been made largely to propose effective control strategies and to evaluate the performance of such strategies under the contexts of different power grid systems. An additional area of research is focused on the development of grid services that may be provided by EVs through integration into controlled charging strategies. In the first effort, EV charging strategies are often proposed in consideration of grid behavior, economic factors, and/or the driving needs of the fleet at the vehicle level. For example, Moses et al. present a study in [34] on the effectiveness of different charge schedules and charge rates under various EV market penetration scenarios. Most notably, results of the study indicate the advantages of scheduling strategies in suppressing peak charging behavior in a variety of different contexts. In another work, Veldman et al. [35] compare the overall effectiveness of peak-minimization and cost-minimization strategies in consideration of financial factors from both a grid perspective as well as from an EV owner perspective. In this comparison, the results emphasize the efficacy of control strategies that optimize EV charging from the broad perspective of the grid, suggesting the need for aggregate EV charging and coordination via a centralized controller. This point is similarly emphasized in [36] by Madzharov et al., who additionally discuss the need for economic incentives and an appropriate regulatory framework to facilitate the effectiveness of the system. Otherwise stated, strict TOU electricity pricing schemes provide ineffective signals for decentralized controlled charging strategies and may negatively impact the operation of the overall grid. A comprehensive survey of the literature on control strategies may be found in the review work conducted by Garcia-Villalobos et al. in [37]. The general agreement in literature, however, trends towards the centralized control of EV fleets as an aggregate flexible load, which may be more easily regulated to provide benefits both for the grid and for EV owners.

With respect to the efforts to realize grid services that may be provided through controlled charging strategies, particular research focus has been directed towards its role in the integration of RES. Several works have targeted the supportive operation of controlled charging strategies with respect to the intermittent behaviors of renewable energy generation technologies. In [38], Soares et al. evaluates the potential of EV fleets to regulate the intermittency of wind-based power generation within a northeastern Brazil context. The article discusses the role that large EV fleets may play in maximizing the utility of wind-based generation and in reducing the requirement for back-up capacity and energy storage for RES deployments. A similar work is presented in [39] by Wu et al. for a solar photovoltaic system. The context of the study focuses on the interactions between EVs with solar-based RES deployments at the residential level, for which economic advantages and load-shifting potential have been proposed for the customer and to the grid, respectively. On this last point, there is research interest into how additional grid services may be derived from the controlled charging of EV fleets. For a detailed overview on this discussion, a review of the literature has been provided by Hu et al. in [40]. The core concept of this body of research, in short, is that control of a sufficiently responsive fleet of EVs provide the grid with the leisure to reduce power loss, to improve power quality, and to more accurately match generation capacities to immediate consumption demands.

2.3.3 Vehicle-to-Grid Technology (V2G)

Also discussed in literature is the possibility to integrate EV technology into smart energy systems as mobile distributed energy storage resources via vehicle-to-grid (V2G) technology. Here, V2G is discussed as an advanced mode of connectivity to the grid for EVs in which both real-time communication and advanced bi-directional power flow technologies enable vehicles to make their battery capacities available to the grid. In contrast, the conventional unidirectional charging mode is referred to as the grid-to-vehicle (G2V) mode. In this discussion, implementation of advanced communication and bi-directional power flow technologies may enable EV fleets to provide key services to the power grid such as peak load shaving, reactive power support, frequency regulation, spinning reserves, and improved support for RES integration. These services may be able to provide a source of revenue for EV owners as well as reduce operational costs for the grid.

A detailed discussion on the potential of and factors involved in successful V2G adoption is provided by Kempton et al. in [39] and [40]. In these articles, the financial feasibility of V2G services were projected and were weighed against impacts on accelerated battery degradation resulting from V2G participation. In summary, V2G cannot be financially justified from the perspective of EV owners except for high-value services such as peak power generation, reactive power support, and spinning reserves [41]. In contrast, the significant battery degradation resulting from participation in services such as supplying baseload power makes it obvious that EV fleets cannot be relied upon to substitute primary power generation capacities. Alternatively, the bi-directional power flow capabilities required for V2G allows sufficiently large fleets of EVs to effectively displace stationary BESS, which provides EVs with the additional functionality of grid energy storage components.

Of particular interest to the work presented in this thesis is the potential of V2G implementation in supplying peak power and in displacing stationary BESS capacities for RES support. In these topics, the literature has largely been focused on quantifying the extent to which these services can be provided to the grid and on evaluating the economic justifications for them. For example, in [43], Sortomme et al. propose and evaluate an operational algorithm that aims to maximize profits for aggregate EV fleets through the provision of peak shaving ancillary services under an US context. Results of the study indicate significant financial incentive considering a range of battery replacement cost scenarios. The authors also note the improvements in the flexibility of the grid provided by V2G implementation, which corresponds to increasing the grid's ability to integrate additional intermittent renewable resources. Further developing this last point, a work presented by Tarroja et al. in [44] evaluated the impacts of various adoption levels of intermittent renewables on the operation of the grid. Particularly, their conclusions highlighted the need for energy storage capacities to regulate the intermittent behavior of RES at high adoption levels. In a subsequent work [45], Tarroja et al. compared V2G-enabled EVs to stationary BESS to determine the functional similarities between the two technologies. In this effort, the authors note the comparative advantages of V2G in achieving higher energy utilization over stationary BESS, as well as the infrastructural and availability limitations of V2G due to the primary transportation purposes of EVs.

2.3.4 Challenges to Electric Vehicle Integration into Smart Energy Systems

Recent popularization of EVs in the automotive market has created the opportunity to transition towards electric mobility as well as the potential to integrate EVs as a key grid component in future smart energy systems. Based on the discussion of the impacts that various EV charging modes may have on the power grid, efforts should be made to mitigate the negative impacts of uncontrolled EV charging behaviors while leveraging the roles of EVs as flexible loads and mobile BESS to provide beneficial services to the grid. The successful integration of EVs into smart energy systems, however, faces challenges on several fronts, which are summarized as follows:

- Market: EVs must sufficiently penetrate into the automotive market to incentivize and justify adoption of advanced charging coordination and supporting infrastructure;
- Technology: advanced communication and information technology, as well as the appropriate control infrastructure to support significant EV adoption and charging coordination must be available to enable EV integration into smart energy systems;
- Policy and regulations: appropriate economic incentives and policies must be set to encourage EV integration, as well as to regulate the role of EVs as grid components;
- Social: behaviors must shift to accommodate the role of EVs for both transportation and as a grid component;
- Planning and implementation: charging infrastructure must sufficiently support the operation of EVs and must be incrementally developed according to market and technological trends to encourage integration into smart energy systems.

For the purposes of this thesis, focus will be placed on addressing the planning and implementation requirements for EV adoption. As such, an investigative work is presented in Chapter 4, which contributes to the literature through the qualification of the applicability of different EV charging modes within smart energy systems, in consideration of the potential impacts of limitations in charging infrastructure on the feasibility of the aforementioned charging modes. Additionally, developments were made on the energy hub model to incorporate the role of EVs as grid energy storage components, which is then integrated into a simulation approach that forecasts the optimal operation of a microgrid system considering varying levels of EV and charging infrastructure adoption.

Chapter 3 Benefits of Complementary Building Operation

The following section is based on previously published works entitled "Impact Assessment of Microgrid Implementation Considering Complementary Building Operation: An Ontario, Canada Case" by Q. Kong et al. [46] and "Investigation of Energy, Emission, and Cost Advantages of Energy Hubs: A Simulation Case Study for Toronto" by Q. Kong et al. [47], and are reproduced with permission from *Energy Conversion and Management* and *IEEE*, respectively. The specific contributions of this thesis's author to these works were: model development, simulation, data processing, results analysis, manuscript preparation and review, and presentation. The supervisors provided guidance and review of the results for journal publication.

3.1 Introduction

Sustainable development has become a major research focus due to emerging attention to climate change. As such, there is growing interest in the adoption of distributed energy resources (DER) into the power grid through the implementation of microgrids. In this context, a microgrid is a configuration of buildings with its own energy generation resources and consumption loads while also maintaining connection to an external power grid, from which it may import and export energy to suit its operational needs [48]. Transition of the centralized power grid infrastructure towards the implementation of microgrid communities has been considered due to several advantages of the microgrid configuration. The main benefits are the reduction of energy losses due power transmission and distribution, increased resilience and energy reliability and security, and reduction in greenhouse gas emissions.

In past studies, focus has been placed on evaluating the applicability of various distributed renewable resources and technologies in microgrid systems. The research aimed to assess the feasibility of certain technologies as distributed energy generation resources and their potential impacts on microgrid operation. In particular, micro-cogeneration of heat and power (μCHP) technology and solar photovoltaics (PV) has been considered for application within commercial and residential microgrids. Isa et al. [49] provide a literature review of the implementation of cogeneration systems in microgrids. Prehoda et al. [50] consider the role of PV applications in microgrids to enhance grid energy security. Camilo et al. [51] provide an economic assessment of PV adoption in residential microgrids considering the cost reduction potential of ESS.

Studies have also been directed towards the methodology of technology selection for microgrid archetypes and the optimization of microgrid operation. Marnay et al. [52] examine the economic and environmental impacts of a microgrid operation in a commercial building system utilizing various technology configurations. The study discusses the potential for operating cost and emission reductions through technology optimization. Bahramirad et al. [53] examine the capacity sizing problem for ESS implementation in microgrids, considering an economic optimization based on capital and operating costs, as well as operational constraints for the function of the ESS. Nguyen et al. [54] present a power scheduling and price-based optimization approach to microgrid operation. Di Somma et al. [55] provide a stochastic programming model for the optimization of operation of a microgrid system with multiple DER technologies. The work also provides an economic and environmental evaluation of the performance of the microgrid system under a proposed operational method.

However, the successful implementation of microgrids and DER technologies is often subject to various geographic and economic conditions. As such, several studies have made efforts to consider the economic and environmental conditions of specific microgrid systems. Biglia et al. [15] present the potential implementation of micro co-generation within a microgrid in Sardinia, Italy, recognizing the economic conditions that proved unfavorable for µCHP implementation within the region. Perara et al. [56] present a case study for a Swiss microgrid consisting of both residential and commercial buildings. The study highlights the operational advantages of a microgrid configuration in integrating renewables and in achieving increased autonomy for the microgrid under Swiss conditions. In another Swiss case study, Kuehner et al. [57] consider the potential for full islanded operation in Cartigny, Switzerland microgrid. The study recognizes conditions that discourage full transition towards renewable generation, as well as the importance of daily and seasonal storage capacities in enabling a more reliable renewable integration within microgrids. In these studies [11], [50], and [51], the effort is mainly directed towards recognizing the specific economic and environmental impacts that result from the adoption of DER technologies in microgrids.

In this paper, a microgrid system that consist of both commercial and residential components was modelled and simulated using a dynamic energy simulation approach. This microgrid takes advantage of the complementary commercial and residential buildings use behavior to demonstrate the microgrid's potential to reduce the required capacity of ESS and to improve energy security for the community. Various DER technology configurations were simulated for the microgrid system, which were evaluated for Ontario, Canada conditions to assess the energy, economic, and environmental impacts of each configuration under a Canadian context. This work is an extension to a previous study conducted using similar simulation scenarios [47]. However, it incorporates additional simulation scenarios to consider the role of distributed PV generation and battery energy storage within the buildings system. Additionally, the focus of this study is on the assessment of electrical power and the potential of the microgrid for islanded operation.

3.2 Case Study

For this case study, a set of buildings that contains both residential and commercial components was considered. This was chosen to take advantage of the complementary building use behavior between residential and commercial buildings, in which residential buildings experience high energy demand in the early and later parts of the day, while commercial buildings experience high energy demand in the middle of the day. In order to maximize the effect of this complementary building use behavior, the number of building units of the residential and commercial building components were scaled such that the annual heating, cooling, and electrical loads of the two components are approximately equal. This resulted in a buildings system that consists of 20 residential buildings (i.e. single family homes) with an average total floor area of 200 m^2 and a single commercial building with a total floor area of 5110 m^2. This buildings system was set as the focus of this study and was investigated to explore the potential advantages and consequences that a microgrid configuration may provide in comparison to standalone operation of each building.

The context for this study was set to Ontario conditions to evaluate the potential benefits of microgrid application under a Canadian setting. Ontario was selected among other Canadian provinces because it has the highest relevance to the microgrid configuration proposed in this work. This is because Ontario has the potential to benefit from microgrid application for energy security and for reducing congestion in power transmission, since the Ontario electrical grid is highly reliant upon central power generation stations and it consists of many high power consumption regions. Furthermore, microgrids are less costly to implement in comparison to power distribution grid expansion for grid development.

Simulations for this building system were conducted using the Transient Systems Simulation (TRNSYS) software, which uses a timestep-based flowsheet simulation approach to perform transient energy balance calculations within simulation scenarios [86]. In this work, annual simulations were conducted using Canadian Weather data for Energy Calculations (CWEC) data for Ontario [87]. Within these simulations, the building system was operated both as a set of standalone buildings and as a cluster in a microgrid.

3.2.1 Operational Configurations for Building System

The two operational configurations considered in this study are as shown in Figure 3.1. In the standalone configuration, buildings fulfilled their individual heating, cooling, and electricity consumption requirement using their own heating, ventilation, and air conditioning (HVAC) and electricity generation systems. In the microgrid configuration, these systems were operated such that all components in the system had access to the total heating, cooling, and electricity generation and storage capacities of the overall building system. In this approach, excess generation from distributed generation components of individual buildings may be directed to meet the electricity demand of its neighbors or stored within the ESS as backup power. The overall microgrid also maintains a connection to an external power grid for electricity imports and exports to support the overall operational needs of the microgrid.

Within the system simulation model, different HVAC components were implemented to provide heating, cooling, and electricity to the buildings in the system in each set of scenarios. The heating loads in the system were addressed using either a conventional boiler system or using µCHP implementation, which was considered for both residential and commercial components. The cooling loads in the system were addressed using only conventional, commercially available air-cooled, electric chillers. Lastly, the electrical loads in the system were met using PV generation, co-generated electricity from µCHP operation, or through energy imports from an external electrical grid. All of these options for addressing the heating, cooling, and electrical loads of the system were explored in this work in separate simulation scenarios.

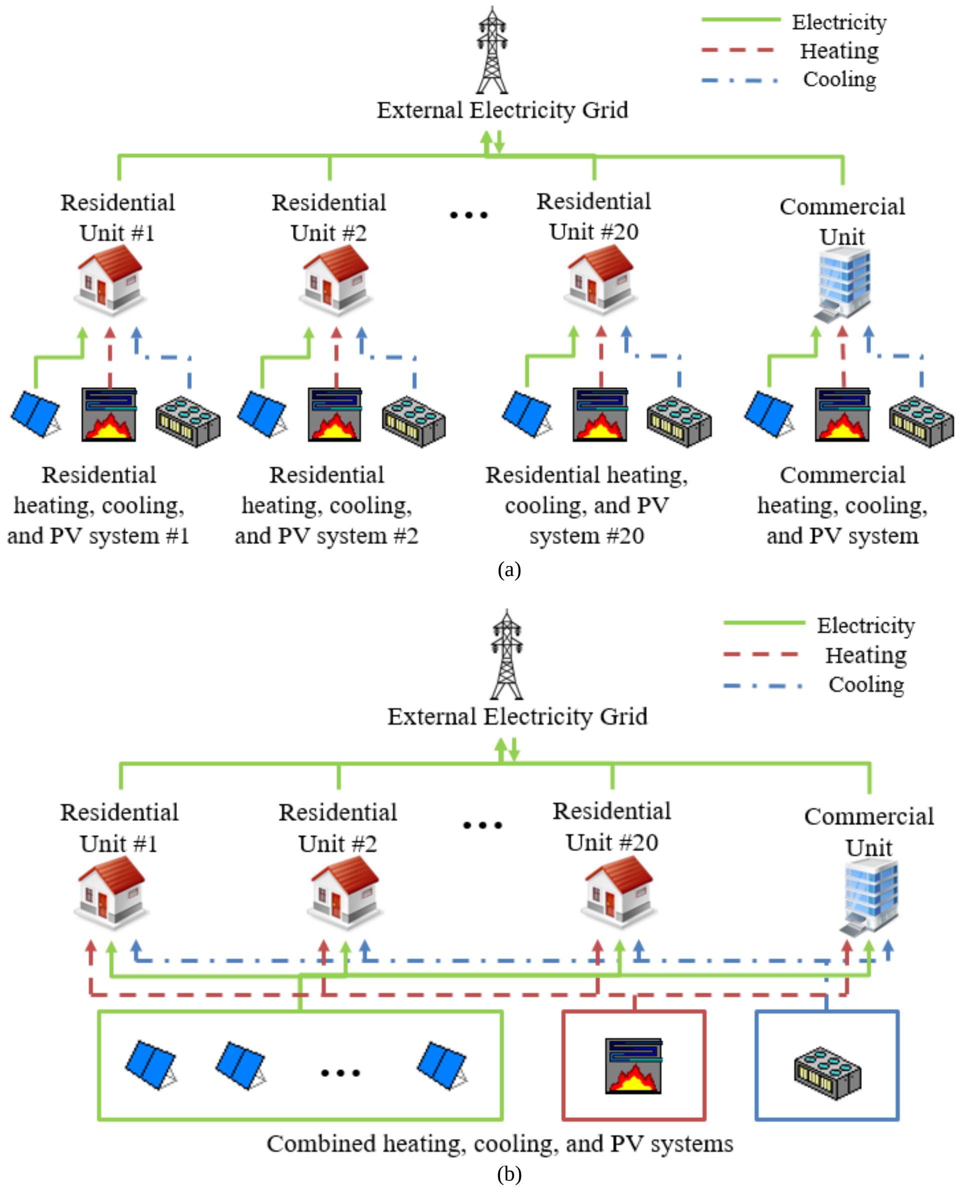


Figure 3.1: Holistic diagram of building system considered in study as a system operating as (a) standalone buildings configuration and (b) microgrid configuration.

The focus of the microgrid system model is on assessing the ability for 'islanded' operation of the microgrid system in terms of its electrical consumption, in which a local network of end-users may sever its connection to the main power grid while retaining functionality using its own energy technology components. Within the model, the heating and cooling components were incorporated to account for the heating and cooling needs of the system. The cooling needs of the system were satisfied using electrical power, which contributes to the electrical load of the buildings. Meanwhile, the heating component significantly impacts the buildings' electrical co-generation potential in scenarios considering µCHP application. For the purposes of this simulation work, µCHP units were assumed to operate under a heat-led operating strategy. This means that the µCHP unit will be operated to meet the required heating load, while co-generated electricity resulting from this operation will be used only as supplementary generation. This was chosen as the most reasonable operating strategy for the scenarios considered in this work, since excess electricity generation from µCHP operation can be exported to the grid to offset grid generation. In contrast, excess heat generation from an electricity-led operating strategy cannot be salvaged and would be considered as wasted generation, since the scope of this study does not consider heat storage and does not assume the presence of an external heat network.

3.2.2 Component Models

In the commercial building model, conventional and µCHP HVAC system components were implemented in different scenarios. Under the conventional model, the heating system is composed of a mid-efficiency boiler (Type700), which was used for both space heating and for domestic hot water (DHW) heating, as well as temperature controllers for the building model component, a water pump (Type113), a fan (Type925), and a heating coil (Type753a). The boiler is specified with a constant average operating efficiency, which represents the overall conversion efficiency of input fuel energy to thermal energy delivered to the boiler fluid. In the residential case, a boiler was used to satisfy the DHW demand while a gas-fired furnace (Type967) and a temperature controller were used for space heating. In the µCHP scenario, all heat generation components were replaced with a natural gas-powered internal combustion engine (ICE), which operates on a heat-led operating strategy. The performance data of the CHP model is set to that of a constant operating efficiency unit with a heat to electrical power output ratio of 2.2:1. This was scaled in size to suit the heating requirements of individual buildings or for the building system as a whole.

The cooling system considers an electric air-cooled chiller with user-input efficiency (Type655) and part-load performance data. Manufacturer data was used to specify the performance of the chillers used in all scenarios [88, 89]. The rest of the cooling system were composed of temperature controllers for the building model component, a water pump (Type113), a fan (Type925), and a cooling coil (Type753a).

Finally, the PV system was implemented as a constant efficiency (Type562) component with an overall efficiency of 12%. Meanwhile, a lead-acid battery component model was implemented using the Type47b component provided by TRNSYS libraries [90], which has an overall round-trip efficiency of 78%.

3.2.3 Building Models

The building models used in this study were incorporated into TRNSYS using the Type56 multizone building model module. The building models were constructed using building geometries obtained from existing buildings in Ontario, which were based on a single-floor residential building and a multi-floor office building that is used for commercial purposes. The residential building model reflects a medium-sized house with an average total floor area of 200 m^2 and a zone volume of 540 m^3 while the commercial building model reflects a 10-story office building with an average floor area of 511 m^2 per floor and a total zone volume of 13500 m^3. The thermal insulation for the residential building consists of walls that have an insulation R factor of 2.85 m^2K/W, a floor with an R factor of 3.53 m^2K/W, and a roof with an R factor of 1.85 m^2K/W. Meanwhile, the thermal insultation for the commercial building consists of walls with an R factor of 3.15 m^2K/W, a basement floor with an R factor of 3.14 m^2K/W, and a roof with an R factor of 3.70 m^2K/W. These building models were provided by Natural Resources Canada (NRCan) and were verified against actual building use data in Ontario for each building type.

The TRNSYS models also incorporate operating temperature setpoint profiles that are summarized in Figure 3.2, which were derived from typical operating hours for each building type and from Occupational Safety and Health Administration (OSHA) standards for building operating temperature ranges [91]. In these profiles, the upper temperature set points of 24 °C and 26 °C were used for activating the air conditioning during times within and outside of building operation hours, respectively. Meanwhile, for heating a lower temperature set point of 21 °C was used for building operation hours and 18 °C was used for times outside of this period. The same temperature setpoint profiles were used for both summer and winter conditions. The models also incorporate infiltration, DHW demand, and internal gain behavior to account for energy losses due to air exchange with the external environment and internal heat gain due to equipment and personnel operations, as well as the heating requirement for DHW consumption. The daily DHW demand used for a single residential building was 166 L/day and the DHW demand for the commercial building was 2000 L/day. The DHW and internal gain profiles were implemented as daily profiles that are as shown in Figure 3.3. The infiltration rates were set as seasonal constants for both the residential and commercial components, which were 0.11/hr in the summer and 0.25/hr in the winter for the residential building model and 0.14/hr in the summer and 0.31/hr in the winter for the commercial building model. The annual heating, cooling, and electricity consumption loads of the building models are as shown in Figure 3.4. The heating load accounts for both space heating as well as the heating required for DHW use.

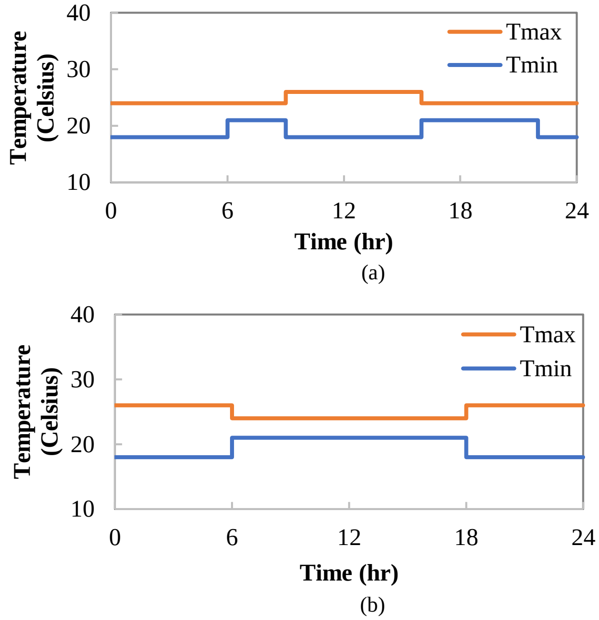
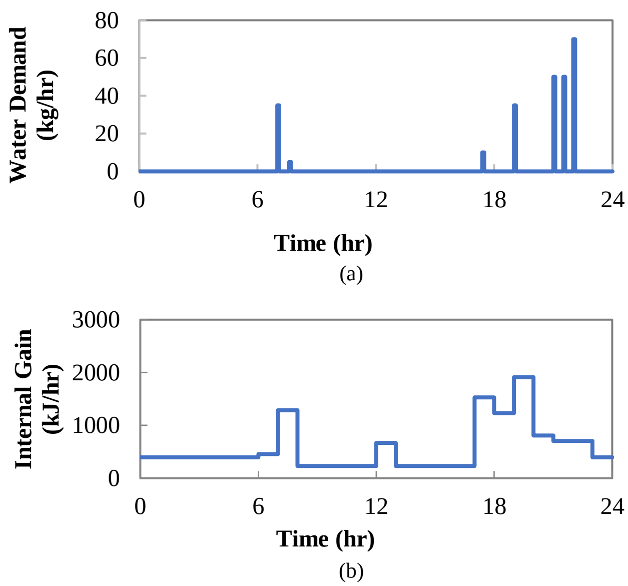


Figure 3.2: Temperature profiles for the (a) residential building and (b) commercial building models.



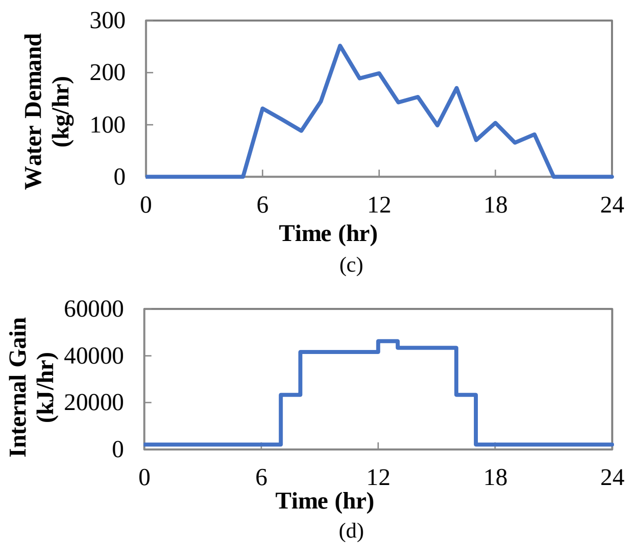


Figure 3.3: DHW demand and internal gain profiles for a single residential building model (a and b) and a commercial building model (c and d).

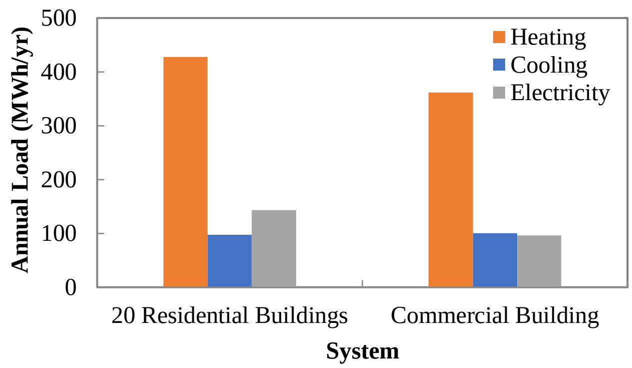


Figure 3.4: Annual heating, cooling, and electricity consumption loads of the residential and commercial components in the simulated building system.

3.2.4 Simulation Cases

In this study, three sets of scenarios were simulated to assess different technology implementations within the buildings system considered. All of which were simulated under both of the operational configurations described in the previous section. In the first set of scenarios, PV implementation was considered as an intermittent renewable resource for local electricity generation. Electrical energy storage using lead-acid batteries was also incorporated to balance the intermittent nature of PV generation. Across scenarios, the degree of adoption of PV within the system was varied and the minimum battery size required for load balancing was determined for each scenario. Only rooftop implementation of building-integrated PV was considered.

The second set of scenarios considered μCHP implementation as an alternative to the conventional boiler system used for space and DHW heating. Similar to the first set of scenarios, this set of scenarios also incorporate a BESS for electricity. Long-term and short-term battery capacities were considered to evaluate the difference in building performance with and without the potential for seasonal electrical storage. There is recognition that the capacity required for seasonal electrical storage is very large for this microgrid, but could be employed in a larger system or in a system with different types of electrical storage.

The last set of scenarios considered the simultaneous implementation of PV and μCHP technologies with battery storage. These scenarios consider varying degrees of adoption of PV as well as varying capacities of battery energy storage for both short-term and seasonal storage purposes. The aim of this final set of scenarios was to consider the potential for islanded operation of the residential and commercial components with the above technology implementations, as well as to assess the operational advantages and consequences of operating the buildings under a microgrid configuration with the presence of both intermittent and seasonal generation.

3.3 Results and Discussion

3.3.1 Energy Analysis

This section assesses the ability of each operational configuration to meet the electrical requirements of the buildings system using local generation resources. In this assessment, each simulated scenario was evaluated to determine the amount of the system's total electrical consumption that is met through local generation resources and through interactions with an external electrical grid. Analysis was also done to evaluate the buildings' export of electricity into the external electricity grid, as well as to determine how much battery energy storage capacity is required in each scenario to eliminate grid exports.

3.3.1.1 PV-Only with Battery Storage

In these scenarios, the level of PV adoption was varied to determine the effect of increasing capacities of intermittent generation, reflecting PV availability in 30%, 50%, and 70% of the buildings. The local storage capacity was also varied in each scenario to determine the minimum amount of storage capacity required to eliminate electricity exports to an external electrical grid. However, a maximum electrical storage capacity equivalent to 5 days of each building's electrical demand was set to reflect realistic applications of short-term storage to complement PV implementation. Any excess generation that cannot be stored within the battery system was assumed to be exported to the external power grid.

The assessment shows that the residential components in the buildings system require significant amounts of electrical energy storage to be able to fully utilize its PV generation potential. This is due to the intermittent nature of PV generation, which requires a large amount of storage capacity to perform load-balancing services for the large mismatch between the building's PV generation and electricity consumption profiles. This behavior is illustrated in Figure 3.5(a). In scenarios with higher PV adoption, a storage capacity exceeding the 5-day storage limit would be required, which results in a significant amount of exported generation.

Meanwhile, the commercial component was found to require little storage capacity as most of its generation can be instantaneously utilized within the building. This is owing to the electricity consumption profile of commercial building operation, which is synergistic with the generation behavior of the PV system, as shown in Figure 3.5(b). However, the geometry of the commercial building limits the availability of its own PV resources, since the commercial building does not have adequate roof space to accommodate sufficient PV generation. Even in scenarios considering a high level of PV adoption, PV generation only provides for 9.0% of the annual electrical consumption of the commercial building.

When considering the scenarios in which the buildings were operated under a microgrid configuration, the simulation results show that the microgrid approach offers advantages in minimizing the storage capacity required to eliminate electricity exports. It was shown that a microgrid configuration requires smaller total battery energy storage capacity than the standalone buildings configuration. This corresponds to an overall decrease in total electricity storage capacity of up to 48.7%. Despite the reduced capacity, the microgrid configuration was still able to fully utilize local generation, resulting in zero electricity exports to the grid. In contrast, the residential component in a standalone buildings configuration had to export up to 36.3% of its annual PV generation due to limits in storage capacity.

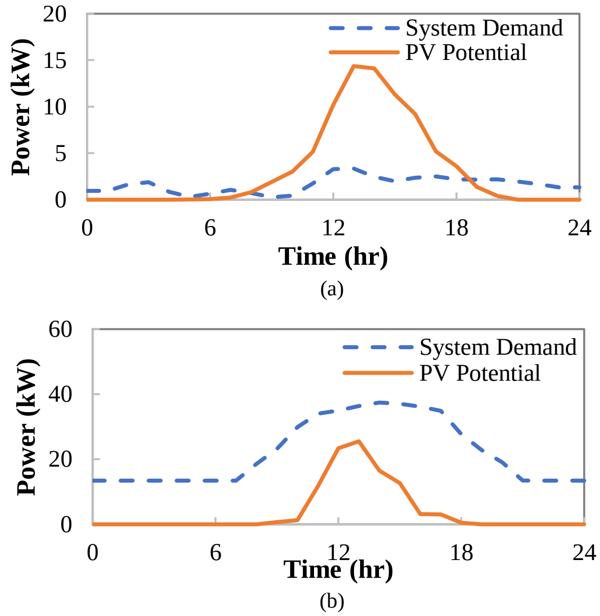


Figure 3.5: Typical PV generation potential and building electrical consumption behavior for (a) residential buildings and (b) commercial buildings, considering a high level of PV adoption.

Furthermore, the microgrid configuration also demonstrated an operational advantage in distributing the excess generation from residential buildings to the commercial building. This allows the overall building system to become less reliant on grid generation. A summary of the comparison between the two operating configurations is shown in Table 3.1. In this table, the contributions to the total consumption of each component were identified based on the flow of electricity within the system. The utilization of the PV system represents electricity flows directly from PV generation to meet the building's consumption, while utilization of the battery system represents excess PV generation that is stored within the battery storage system, which provides electricity to meet building consumption during non-PV generation periods. Grid imports represent necessary grid generation whenever the PV-battery system was not able to meet the building's demand. Finally, grid exports represent excess generation that was exported to the external power grid, due to capacity limits in the buildings' energy storage system.

Table 3.1: Summary of energy assessment for PV-only scenarios operating under a standalone systems configuration and under a microgrid configuration

System Configuration	Standalone Buildings						Microgrid		
System Component	Residential			Commercial					
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%	30%	50%	70%
Utilization of PV System (% of Annual Consumption)	36.6%	42.1%	44.9%	4.1%	6.7%	9.0%	17.0%	21.8%	24.4%
Grid Import Electricity (% of Annual Consumption)	36.0%	13.5%	6.8%	95.9%	93.2%	90.3%	79.7%	67.6%	55.6%
Utilization of Battery System (% of Annual Consumption)	27.2%	44.2%	48.0%	0.0%	0.1%	0.6%	3.2%	10.6%	19.9%
Minimum Battery Size (kWh)	1960	3040	3040	0	27	63	350	744	1513
Electricity Export to Grid (% of Annual PV Generation)	0.0%	17.5%	36.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

3.3.1.2 µCHP-Only with Battery Storage

The second set of scenarios considered was the implementation of µCHP along with local battery energy storage. Similar to the PV-only scenarios, analysis was done to assess the system's ability for islanded operation as well as on the storage capacity required to maximize use of the local generating capacity. In these scenarios, co-generation was shown to exhibit seasonal operation behavior due to the heat-led operation mode considered in the simulation model. As such, seasonal storage scenarios were considered in addition to the short-term storage options presented for PV-only scenarios. For the seasonal storage scenarios, the maximum storage capacity that was considered reasonable for the simulation was set to the amount equivalent to 50 days of average electrical consumption.

For the scenarios in this set that considered short-term storage, the results showed that local generation contributed approximately equal amounts to the annual electrical load of both residential and commercial components. In the scenarios considering microgrid configuration, it was seen that a larger portion of the system's electrical consumption can be met through local generation, as summarized in Table 3.2. This is largely due to the advantages that a microgrid configuration has in being able to better distribute local generation resources, which allows more of the intermittent generation to be utilized immediate by a complementary component in the microgrid system. Overall, a microgrid configuration results in a decrease in grid imports of approximately 4 percentage points. The microgrid configuration also results in a reduction in overall required storage capacity of 6.7%.

Table 3.2: Summary of comparison between standalone buildings configuration and microgrid configuration for μCHP implementation with short-term electrical energy storage

System Configuration	Standalone Buildings		Microgrid
System Component	Residential	Commercial	
Utilization of μCHP Generation (% of Annual Consumption)	40.46%	41.33%	47.76%
Grid Import Electricity (% of Annual Consumption)	47.10%	46.26%	42.69%
Utilization of Battery Storage (% of Annual Consumption)	12.43%	12.41%	9.55%
Minimum Battery Size Required (kWh)	3046	3808	6397
Electricity Export to Grid (% of Annual PV Generation)	20.77%	22.18%	27.73%

In the case of seasonal storage, the simulation results showed similar trends as in the short-term storage scenarios. Again, a microgrid configuration allowed the system to better distribute its electricity generation resources to complementary components in the system. However, the difference observed in the long-term storage scenarios was that there was a notably lower reliance on grid generation, as a larger portion of the system's annual demand can be met through stored electricity from seasonal μCHP operation. This corresponds to an additional offset of approximately 20 percentage points of the annual electrical grid load of the system than in the short-term storage scenarios. Furthermore, the long-term storage scenarios showed that a microgrid configuration requires a larger electrical energy storage capacity than the total sum required by a standalone buildings configuration, by an additional 15%. This was found to be due to the increase in energy efficiency within the system. As more of the instantaneous generation is utilized due to improved distribution amongst system components, there is less energy lost due to energy conversion during the short-term electricity storage process. The increased size of energy storage capacity also corresponds to a larger portion of the annual consumption being satisfied by stored electricity, which is an increase of between 2 – 3 percentage points as compared to the standalone buildings configuration. The results of this analysis are as shown in Table 3.3.

Table 3.3: Summary of comparison between standalone buildings configuration and microgrid configuration for µCHP implementation with long-term electrical energy storage

System Configuration	Standalone Buildings		Microgrid
System Component	Residential	Commercial	
Utilization of µCHP Generation (% of Annual Consumption)	40.76%	41.52%	47.94%
Grid Import Electricity (% of Annual Consumption)	33.33%	31.73%	22.71%
Utilization of Battery Storage (% of Annual Consumption)	25.92%	26.75%	29.34%
Minimum Battery Size Required (kWh)	23500	30649	62303
Electricity Export to Grid (% of Annual PV Generation)	0.00%	0.00%	0.00%

3.3.1.3 PV and µCHP with Battery Storage

The final set of scenarios considered both the implementation of PV and µCHP technology with battery electrical energy storage. In this set of scenarios, the level of PV utilization was varied and varying levels of battery capacity installation were simulated. The levels of battery capacity installation considered were the capacity equivalents of 2 days, 5 days, and 50 days of standalone operation. These conditions were selected to evaluate changes in storage capacity between daily, weekly, and seasonal electrical energy storage and their effect on the system's reliance on grid generation.

In the comparison between the daily and weekly storage capacity scenarios, the results showed that there was little difference between the two sets of scenarios in terms of energy security for the microgrid. The storage capacity in both scenarios were not able to accommodate the seasonal generation behavior of the µCHP system and were used mostly for balancing the intermittent generation behavior of the PV system. Thus the increased cost of batteries for weekly storage is generally not warranted. In the assessment of residential and commercial components in the standalone buildings scenarios, the residential components were able to satisfy a larger portion of its annual electrical load using local generation, while commercial components had to rely on grid electricity imports for a significant portion of its annual electricity consumption. Meanwhile, co-generation from µCHP could only contribute to the instantaneous demand of the building due to the lack of seasonal battery storage capacity in these scenarios.

The microgrid configuration scenarios considering short-term electrical energy storage showed improved system utilization of local generation and storage capacities. This results in an overall decreased reliability on imported electricity for system operation, which corresponds to a decrease in consumption of grid generation by up to 10.5% in cases of high PV adoption. The results of the comparison between the standalone buildings configuration and the microgrid configuration are as summarized in Table 3.4 and

Table 3.5 for 2-day storage scenarios and

Table 3.6 and

Table 3.7 for 5-day storage scenarios.

Table 3.4: Summary of energy assessment of residential and commercial components for PV-µCHP implementation in standalone buildings configuration scenario with 2-day electrical energy storage

System Component	Residential			Commercial		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Utilization of PV-µCHP System (% of Annual Consumption)	60.5%	64.6%	66.8%	44.9%	47.1%	49.0%
Grid Import Electricity (% of Annual Consumption)	23.9%	12.1%	4.6%	45.2%	43.3%	41.5%
Utilization of Battery System (% of Annual Consumption)	15.6%	23.3%	28.7%	9.9%	9.6%	9.5%
Minimum Battery Size Required (kWh)	1138	1138	1138	1422	1422	1422
Electricity Export to Grid (% of Annual Generation)	26.8%	31.0%	36.6%	24.9%	25.2%	25.4%

Table 3.5: Summary of comparison of energy assessment for standalone buildings and microgrid configurations for 2-day storage in PV-µCHP-battery implementation scenarios

System Configuration	Standalone Buildings			Microgrid		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Utilization of PV-µCHP-Battery System (% of Annual Consumption)	64.3%	70.7%	75.1%	70.0%	78.4%	85.6%
Grid Import Electricity (% of Annual Consumption)	35.7%	29.3%	24.9%	30.0%	21.6%	14.4%
Minimum Battery Size Required (kWh)	2560	2560	2560	2560	2560	2560

Table 3.6: Summary of energy assessment of residential and commercial components for PV-µCHP implementation in standalone buildings configuration scenario with 5-day electrical energy storage

System Component	Residential			Commercial		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Utilization of PV-µCHP System (% of Annual Consumption)	60.5%	64.6%	66.9%	45.0%	47.2%	49.1%
Grid Import Electricity (% of Annual Consumption)	22.0%	10.2%	1.3%	43.4%	41.5%	39.6%
Utilization of Battery System (% of Annual Consumption)	17.5%	25.2%	31.8%	11.7%	11.4%	11.2%
Minimum Battery Size Required (kWh)	2843	2843	2843	3554	3554	3554
Electricity Export to Grid (% of Annual Generation)	25.8%	30.2%	35.1%	22.7%	23.1%	23.4%

Table 3.7: Summary of comparison of energy assessment for standalone buildings and microgrid configurations for 5-day storage in PV-µCHP-battery implementation scenarios

System Configuration	Standalone Buildings			Microgrid		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Utilization of PV- µCHP -Battery System (% of Annual Consumption)	66.2%	72.6%	77.5%	71.9%	80.3%	87.5%
Grid Import Electricity (% of Annual Consumption)	33.8%	27.4%	22.5%	28.1%	19.7%	12.5%
Minimum Battery Size Required (kWh)	6397	6397	6397	6397	6397	6397

In the seasonal storage scenarios, the results indicated that the residential system components in a standalone buildings scenario were able to operate fully independently of grid imports while also exporting excess electricity to the grid. This was due to the combined electricity generation potential of PV and µCHP application, which exceeded the annual electrical load of the system. The residential systems were able to take advantage of presence of seasonal electrical energy storage for both load-balancing for intermittent PV generation as well as for seasonal electrical energy storage for µCHP operation. In a similar fashion, commercial system components were able to completely utilize its annual generation potential and only relied on grid generation for up to 27.7% of its annual load, under scenarios with low PV adoption.

When considering a microgrid configuration, the full range of benefits of a microgrid configuration were utilized to enable islanded operation for the overall buildings system. In this configuration, the excess generation from the residential system components can be distributed to the commercial components. This allows the entire microgrid system to operate as a standalone system rather than just the residential components. Meanwhile, the residential components benefit from the microgrid configuration by utilizing the shared electrical energy storage capacity of the commercial component, thereby reducing its need for large installations of electrical energy storage. Overall, this corresponds to a reduction in total installed electrical energy storage capacity of 3.8%. A summary of the energy assessment of individual system components is as shown in Table 3.8 and the comparison between standalone buildings and microgrid configurations is as shown in

Table 3.9.

Table 3.8: Summary of energy assessment of residential and commercial components for PV-µCHP implementation in standalone buildings configuration scenario with 50-day electrical energy storage

System Component	Residential			Commercial		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Utilization of PV-µCHP System (% of Annual Consumption)	61.1%	65.2%	66.9%	45.2%	47.3%	49.3%
Grid Import Electricity (% of Annual Consumption)	1.7%	0.0%	0.0%	27.7%	25.1%	22.5%
Utilization of Battery System (% of Annual Consumption)	37.2%	34.8%	33.1%	27.1%	27.6%	28.2%
Minimum Battery Size Required (kWh)	30460	30460	30460	32879	34412	35996
Electricity Export to Grid (% of Annual Generation)	5.4%	20.2%	32.9%	0.0%	0.0%	0.0%

Table 3.9: Summary of comparison of energy assessment for standalone buildings and microgrid configurations for 50-day battery storage in PV-µCHP-battery implementation scenarios

System Configuration	Standalone Buildings			Microgrid		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%

Utilization of PV-μCHP-Battery System (% of Annual Consumption)	83.9%	86.2%	87.6%	94.1%	100.0%	100.0%
Grid Import Electricity (% of Annual Consumption)	16.1%	13.8%	12.4%	5.9%	0.0%	0.0%
Minimum Battery Size Required (kWh)	63341	64873	66457	63968	63968	63968

3.3.2 Environmental Assessment

In this section, an environmental perspective is taken to assess the buildings system operating under a microgrid configuration. In this assessment, the emissions of the various energy streams present in the system were evaluated using emission factors. An emission factor of 235 g GHG/kWh was selected for natural gas consumption while an emission factor of 77 g GHG/kWh was selected for grid-generated electricity [92, 93]. The emission factor for natural gas consumption is typical of natural gas use in building HVAC systems, while the emission factor for grid generation was selected based on Ontario's mix of generation resources, which is composed mostly of low-emission sources such as nuclear and hydro. Furthermore, excess electricity generation from simulated scenarios was assumed to be exported to the local external electricity grid, which directly offsets emissions associated with grid generation. For comparison, the emission analysis for the base case scenario, in which neither PV nor μCHP were implemented, are as shown in Table 3.10.

Table 3.10: Summary of emissions comparison of microgrid configuration and standalone buildings configuration for base case scenarios

System Configuration	Standalone Buildings		Microgrid
	Residential	Commercial	
Emissions from Natural Gas Consumption (tonnes GHG/yr)	105.2	77.2	175.9
Emissions from Grid Consumption (tonnes GHG/yr)	16.5	20.3	35.5
Emission Reduction from Electricity Exports (tonnes GHG/yr)	0.0	0.0	0.0
Total Emissions for Electricity (tonnes GHG/yr)	16.5	20.3	35.5
Total Emissions (tonnes GHG/yr)	121.7	97.5	211.4

3.3.2.1 PV-Only with Battery Storage

In both the residential and commercial components of the system, emission contributions from natural gas consumption for building heating accounted for the majority of the emissions of the system. Overall, it was shown that PV adoption resulted in annual emission reductions of up to

20.7% in residential buildings and up to 2.0% in commercial buildings in cases of high PV adoption, as shown in Table 3.11.

Table 3.11: Summary of emissions assessment for residential and commercial components in PV-only scenarios

System Component	Residential			Commercial		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Emissions from Natural Gas Consumption (tonnes GHG/yr)	105.2	105.2	105.2	77.2	77.2	77.2
Emissions from Grid Consumption (tonnes GHG/yr)	5.9	2.2	1.1	19.5	18.9	18.3
Emission Reduction from Electricity Exports (tonnes GHG/yr)	0.0	-3.4	-9.7	0.0	0.0	0.0
Total Emissions for Electricity (tonnes GHG/yr)	5.9	-1.2	-8.7	19.5	18.9	18.3
Total Emissions (tonnes GHG/yr)	111.2	104.1	96.6	96.7	96.1	95.6

A comparison between the microgrid configuration and the standalone buildings configuration was also done to evaluate the advantages and consequences of microgrid operation. In this comparison, however, the emission contributions due to natural gas and electricity consumption were considered separately. This was done to isolate the environmental impacts of the electrical system, which is largely dependent on the resource mix of the electrical grid, from the environmental impacts of natural gas consumption, which is fuel-specific.

Considering the electrical needs of the system, the assessment indicated that a microgrid configuration resulted in a higher annual emission rate than a system of standalone buildings. In this case, the increase in emissions was found to be due to energy lost during short-term electrical energy storage. As discussed in the energy analysis section, a microgrid configuration has advantages in increased utilization of the storage capacity of the total building system. However, increased utility of electricity storage decreases emission reduction potential due to losses incurred during energy storage. This was found to increase with higher levels of PV adoption, due to the increased utility of electrical storage capacities. Overall, a microgrid configuration corresponds to an increase in emissions from electricity usage of as high as 104%, as compared to standalone operation. Meanwhile, the emissions due to natural gas consumption varied only between the two operational configurations considered, with a 11% reduction in emissions from natural gas consumption resulting from the microgrid configuration. The results of the environmental analysis for PV scenarios are as shown in Table 3.12.

Table 3.12: Summary of emissions comparison of microgrid configuration and standalone buildings configuration for PV scenarios

System Configuration	Standalone Buildings			Microgrid		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%
Emissions from Grid Consumption (tonnes GHG/yr)	25.38	21.11	19.39	28.28	23.96	19.71
Emission Reduction from Electricity Exports (tonnes GHG/yr)	0.00	-3.36	-9.75	0.00	0.00	0.00
Total Emissions for Electricity (tonnes GHG/yr)	25.38	17.75	9.65	28.28	23.96	19.71

3.3.2.2 µCHP-Only with Battery Storage

In the simulation scenarios considering µCHP implementation, the results of the environmental assessment showed that µCHP application generally result in higher emissions from increased natural gas consumption as compared to conventional heating systems. This was due to the lower operating efficiency of µCHP implementation in the conversion of natural gas to heating for the system, since a part of the chemical energy is converted into electricity in the co-generation process. As a result, both residential and commercial components in the system experienced higher emission rates from µCHP operation. A summary of this assessment is shown in Table 3.13. The overall increase in emissions is because Ontario's emission factor for grid generation is comparatively lower than the emission factor for natural gas consumption.

Table 3.13: Summary of emissions assessment for residential and commercial components in µCHP-only scenarios

System Component	Residential		Commercial	
Electrical Energy Storage Capacity (# of days of operation)	5-day	50-day	5-day	50-day
Emissions from Natural Gas Consumption (tonnes GHG/yr)	186.3	186.3	218.4	218.4
Emissions from Grid Consumption (tonnes GHG/yr)	7.9	5.6	9.4	6.5
Emission Reduction from Electricity Exports (tonnes GHG/yr)	-2.7	0.0	-3.5	0.0

Total Emissions for Electricity (tonnes GHG/yr)	5.2	5.6	6.0	6.5
Total Emissions (tonnes GHG/yr)	191.5	191.8	224.3	224.9

The analysis also showed that in a microgrid configuration the result is lower annual emissions for the system as compared to a system of standalone buildings. This was because, in contrast to a system with intermittent electricity generation, a microgrid system considering µCHP implementation incurs environmental benefits mainly from the improved distribution of instantaneous generation among system components. This has the consequence of reducing the overall need for electricity storage, as more of co-generated electricity can be utilized through load-matching with the consumption profile of the overall building system. The assessment also showed that, similar to the trends observed in the PV scenarios, smaller storage capacities resulted in lower annual emissions. The results for the µCHP scenarios are as shown in Table 3.14.

Table 3.14: Summary of emissions comparison of microgrid configuration and standalone buildings configuration for µCHP scenarios

System Configuration	Standalone Buildings		Microgrid	
Electrical Energy Storage Capacity (# of days of operation)	5-day	50-day	5-day	50-day
Emissions from Grid Consumption (tonnes GHG/yr)	17.3	12.0	14.1	7.5
Emission Reduction from Electricity Exports (tonnes GHG/yr)	-6.1	0.0	-7.9	0.0
Total Emissions for Electricity (tonnes GHG/yr)	11.2	12.0	6.2	7.5

3.3.2.3 PV and µCHP with Battery Storage

From the energy assessment, it was revealed that the combination of the two technologies resulted in improved operation of the microgrid configuration. This is because the combined intermittent electrical generation potential could be used to satisfy a significant portion of the instantaneous demand of the overall system. In doing so, the system is able to minimize the use of battery energy storage for intermittent load-balancing, thereby reducing energy conversion losses due to energy storage. This also results in increased generation of excess electricity during seasons with µCHP operation, which increases the amount of electricity export potential of the microgrid configuration in comparison to a standalone buildings configuration.

From an emissions perspective, the microgrid configuration allows the system to minimize emissions due to consumption of grid generation, as well as increase the system's emission reduction potential from increased energy efficiency within the system. Overall, the microgrid configuration has been shown to reduce emissions due to electricity consumption by up to 5.26 tonnes GHG/yr, which corresponds to an overall decrease in system emissions of up 1.3%. The results of this assessment are as shown in Table 3.15 and Table 3.16.

Table 3.15: Summary of emissions assessment of microgrid configurations for PV and µCHP scenarios

Amount of Storage (# of days equivalent)	2-day			5-day			50-day		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%	30%	50%	70%
Emissions from Natural Gas Consumption (tonnes GHG/yr)	401.3	401.3	401.3	401.3	401.3	401.3	401.3	401.3	401.3
Emissions from Grid Consumption (tonnes GHG/yr)	9.9	7.1	4.8	9.3	6.5	4.1	1.9	0.0	0.0
Emission Reduction from Electricity Exports (tonnes GHG/yr)	-11.3	-13.2	-15.5	-10.6	-12.6	-14.9	-1.8	-4.5	-9.1
Total Emissions for Electricity (tonnes GHG/yr)	-1.4	-6.1	-10.7	-1.3	-6.1	-10.7	0.1	-4.5	-9.1
Total Emissions (tonnes GHG/yr)	399.9	395.2	390.6	400.0	395.2	390.6	401.4	396.8	392.2

Table 3.16: Summary of emissions assessment of standalone buildings configurations for PV and µCHP scenarios

Amount of Storage (# of days equivalent)	2-day			5-day			50-day		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%	30%	50%	70%
Emissions from Natural Gas Consumption (tonnes GHG/yr)	404.6	404.6	404.6	404.6	404.6	404.6	404.6	404.6	404.6
Emissions from Grid Consumption (tonnes GHG/yr)	13.2	10.9	9.2	12.5	10.2	8.3	6.0	2.9	2.3
Emission Reduction from Electricity Exports (tonnes GHG/yr)	-9.3	-11.7	-14.8	-8.8	-11.1	-14.1	-1.0	-2.6	-7.0
Total Emissions for Electricity (tonnes GHG/yr)	3.9	-0.8	-5.6	3.8	-1.0	-5.7	4.9	0.3	-4.7
Total Emissions (tonnes GHG/yr)	408.5	403.8	399.0	408.4	403.7	398.9	409.6	405.0	399.9

3.3.3 Operating Costs Assessment

In this analysis, Ontario's time-of-use electricity pricing scheme was used to evaluate the costs of electricity imports from the grid and a constant purchase price was used to evaluate natural gas consumption. The cost for natural gas used in this assessment is 0.0214 $CDN/kWh. Meanwhile, the cost of electricity consumption was calculated using Ontario's time-of-use rates, which consists of seasonal pricing schemes for off-peak (0.101 $CDN/kWh), mid-peak (0.131 $CDN/kWh), and on-peak (0.168 $CDN/kWh) electricity consumption on weekdays and a constant off-peak price on weekends [94]. The rates used in this study incorporate regulatory, transmission, and distribution charges. The time-of-use periods are as shown in Figure 3.6. Finally, electricity exports were evaluated using the feed-in tariff (FIT) rates set out under Ontario's 2017 MicroFIT program, which outlines the electricity purchase rates for electricity that is exported to the grid. Currently, the MicroFIT program offers high compensation rates for exported electricity, although this is expected to decrease in the future. In this study, a feed-in tariff rate of 0.192 $CDN/kWh was used.

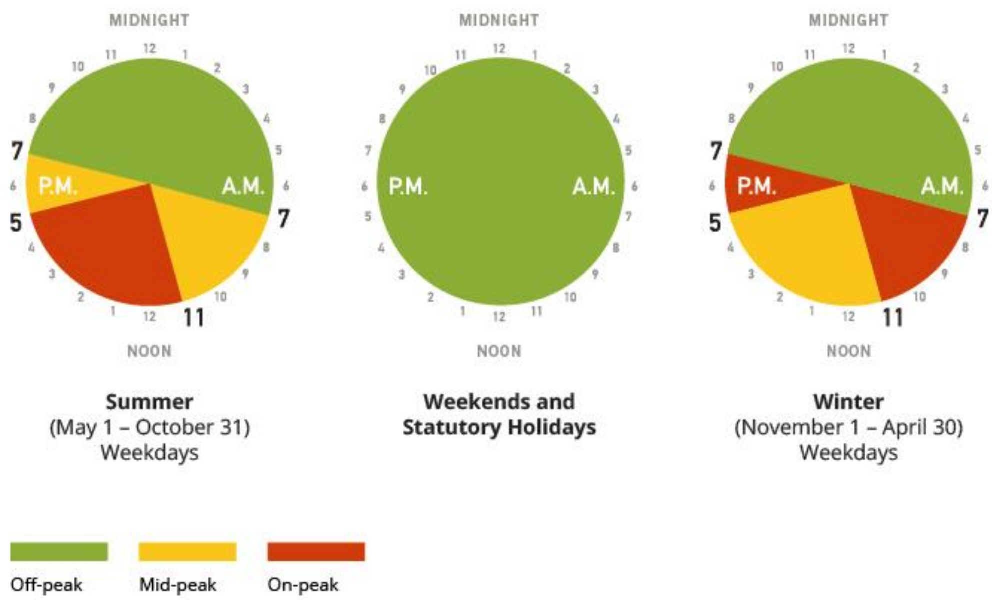


Figure 3.6: Time-of-use rates for electricity consumption in Ontario for a residential user.

3.3.3.1 PV-Only with Battery Storage

The results of the operating costs assessment indicated that, from a macroscopic perspective, natural gas consumption contributes to a small portion of the annual operating costs of the system. The majority of operating costs result from the consumption of grid electricity, which composes 73.0% and 81.9% of annual operating costs for residential and commercial components, respectively. When considering PV adoption, up to 9.3% of annual costs in the commercial components can be reduced. In the case of residential components, scenarios with high PV adoption resulted in a net profit from system operation. In these scenarios, residential components were able to make a profit of up to 36.5% of annual operating costs incurred in scenarios without PV adoption. Overall, power production from PV adoption directly reduces the costs of electricity consumption within the system, since it effectively acts as a source of cost-free electricity during operation. The more profitable use of PV generation, however, is for electricity export to the external electricity grid. This is because it is more economic, under Ontario's electricity prices, to sell electricity back to the grid through the microFIT program.

Under this scheme, residential and commercial components of the system were able to profit more from energy exports than from using PV generation to meet local energy demands. These conditions are favorable towards electricity exports and, as a result, implies the advantages that a microgrid configuration provide are not economically beneficial. The results of the economic analysis reflect this and, as shown in Table 3.17, indicate that a system operating under a microgrid configuration incur up to 105.2% additional annual operating costs as compared to a system operating as standalone buildings.

Table 3.17: Annual operating cost comparison of standalone buildings and microgrid configurations for PV adoption scenarios

System Configuration	Level of PV Adoption (% of available roof space)		
	30%	50%	70%
Operating Cost of Microgrid Configuration ($/yr)	58,967	52,260	45,829
Operating Cost of Standalone Buildings Configuration ($/yr)	55,672	40,949	22,330

3.3.3.2 µCHP-Only with Battery Storage

The operating costs assessment for the µCHP scenarios indicated that µCHP adoption is a profitable option, since the additional natural gas consumption required for heating is outweighed by the additional electricity generation potential. The analysis also indicate that smaller electrical energy storage capacities are more economic for the system, as it forces excess generation to be exported to the grid.

The operating costs assessment for the µCHP scenarios also indicate that a microgrid configuration is more economic for the overall system than a standalone buildings configuration. This was because the advantages that a microgrid configuration provides in distributing instantaneous generation outweighs the losses incurred in battery energy storage. Under these conditions, a microgrid configuration allows buildings to reduce costs from the consumption of grid electricity while also minimizing losses in FIT profits due to the operational behavior of seasonal electrical energy storage. A summary of this comparison is as shown in Table 3.18. Overall, a microgrid configuration results in a reduction in annual operating costs of up to 18.9% of costs incurred in a standalone buildings scenario.

Table 3.18: Annual operating cost comparison of standalone buildings and microgrid configurations for μCHP adoption scenarios

System Configuration	Amount of Storage (# of days equivalent)	
	5-day	50-day
Operating Cost of Microgrid Configuration ($/yr)	40,300	53,035
Operating Cost of Standalone Buildings Configuration ($/yr)	49,670	59,276

3.3.3.3 PV and μCHP with Battery Storage

The scenarios considering the implementation of both PV and μCHP were shown to benefit most from operating under a microgrid configuration. This was because microgrid operation minimized energy losses due to intermittent load-balancing by providing improved distribution of intermittent generation, thereby increasing the total amount of local generation potential that could be used to offset electricity costs. The operating costs assessment showed that microgrid operation resulted in a reduction in annual operating costs of up to 61.2% of costs incurred in a standalone buildings configuration. A summary of the results of this assessment are as shown in Table 3.19.

Table 3.19: Annual operating cost comparison of standalone buildings and microgrid configurations for PV and μCHP adoption scenarios

Amount of Storage (# of days equivalent)	2-day			5-day			50-day		
Level of PV Adoption (% of available roof space)	30%	50%	70%	30%	50%	70%	30%	50%	70%
Operating Cost of Microgrid Configuration ($/yr)	23,856	14,668	5,474	24,959	15,756	6,523	40,268	32,501	24,645
Operating Cost of Standalone Buildings Configuration ($/yr)	34,092	24,472	14,111	34,896	25,247	15,138	47,602	40,118	28,352

Chapter 4 Assessment of Charging Infrastructure in Smart Grids

The following section is based on previously published work entitled "The Role of Charging Infrastructure in Electric Vehicle Implementation within Smart Grids" by Q. Kong et al [58]. and is reproduced by permission from *Energies*. The specific contributions of this thesis's author to this work were: data collection, model development, simulation, data processing, results analysis, and manuscript preparation and review. The supervisors provided guidance and review of the results for journal publication.

4.1 Introduction

Depleting natural fossil fuel resources and increased concern over the environmental impacts of high greenhouse gas (GHG) emissions have led to significant development of renewable and sustainable energy resources and technologies. Moreover, advancements in information and communication technology and increasing penetration of distributed energy resources (DER) have sparked a shift from the traditional centralized power infrastructure towards a decentralized energy network configuration. Motivated by this transition, the smart grid concept has been proposed as a future energy distribution framework, which aims to leverage various DERs and communication technologies to yield advantages in overall grid efficiency, flexibility, and reliability [2]. In one aspect, a decentralized energy network has the potential to reduce active power losses through optimal planning of DER deployment [2, 3]. In another, appropriate implementation of communication technologies will enable optimal operation of DERs within the smart grid context, accommodating increasing integration of renewable energy generation, energy storage systems (ESS), and future DER technologies [24]. Lastly, a system with sufficient local DER capacities enables operation under an islanded mode in order to ensure local energy security [61].

Concurrent to the transition towards a decentralized energy framework, mobility electrification in the transportation industry introduces electric vehicles (EV) as another potential DER, which can integrate into the smart grid to provide operational and planning benefits. While previous studies have addressed the various operational modes of EV integration and their corresponding advantages and disadvantages [6–11], there is a gap in the literature on quantifying the impact of charging infrastructure in serving as the interlinkage between EV fleets and the smart grid. This work addresses one of the common assumptions made in smart grid-related studies on EV integration, which is the adequate availability of charging infrastructure to facilitate EV fleet operation.

4.1.1 Literature Review of Smart Grid-Related Studies

In literature, the characteristics of systems incorporating DERs are often studied under an energy hub or microgrid context [65], [66]. In particular, both avenues of research emphasize the use of interconnected energy networks and communication technology to optimize the dispatch of energy vectors in response to intermittent power generation behavior, variable energy costs, and loss of connectivity to external energy networks. These studies generally consist of modelling and optimization of the flow of energy vectors within an (multi-) energy hub system, for which the foundational mathematical model and optimization approach is discussed by Geidl in [23]. Extensions to this model has been proposed to account for energy storage losses and part-load efficiencies by Evins et al. in [25], which improves the accuracy of the model by further accounting for realistic system behaviors and characteristics. Meanwhile, the energy hub model has been used in various studies to consider the applicability and characteristics of different DER technology configurations of energy hubs. For example, Vahid-Pakdel et al. [67] applied the model to study a complex multi-carrier energy hub system incorporating distributed wind-based power generation, district heating network, demand response (DR) programs, and both thermal and electrical energy markets. In another study, Biglia et al. [15] developed the energy hub model to perform dynamic simulation of an existing multi-energy system based on the Brotzu hospital system, under a Sardinia, Italy context. The case study demonstrates modeling of realistic energy consumption behavior of the hospital complex, as well as simulation and analysis of potential combined heat and power (CHP) implementation within the system based on operational and economic criterion. With respect to the characteristics of energy hub systems, particular note has been made by Maroufmashat et al. in [68] as to the high potential for optimized energy vector dispatch in systems containing a wide variety of load behaviors.

As to the applicability of different DERs within the smart grid context, several technologies have been considered in literature. Among these, solar- and wind-based resources have been discussed as the most favorable candidates for integration into the existing power grid as distributed renewable generation capacities [69]. However, the intermittent generation behavior of such renewable resources was noted as one of the major challenges of incorporating them into the power grid [44]. In [70], Bukhsh et al. have proposed to match flexible consumption loads to complement uncertain renewable generation behavior through DR programs as a solution. Similar approaches using DR programs have been considered in [71] by Nwulu et al. and in [12] by Richardson et al. under different test systems and conditions. Such strategies, however, are contingent on the availability of sufficient flexible loads within the system. Alternative to the DR approach, implementation of ESS to address the intermittency of renewable generation has been studied in [13] by Hill et al. and in [72] by Santos et al. In these studies, emphasis has been made to highlight the role of ESS in compensating for the variability of renewable generation technologies, which has been discussed as a key requirement for significant adoption of renewable resources. Of course, while the optimal implementation of renewable generation will depend on unique system conditions, it is foreseeable that both flexible loads and energy storage capacities will play important roles in their implementation.

In addition to their roles for supporting intermittent renewable generation, energy storage systems as a DER has been considered for additional operational benefits. In one instance, the use of ESS for peak load shaving has been evaluated in [73] by Martins et al., in which the economic advantages of peak load shaving are discussed in consideration of industrial load profiles, under a Germany context. Other implementations of ESS for peak load shaving services have also been studied in hybrid systems. In [74], Wang et al. study a hybrid solar photovoltaic-battery ESS system for peak-shaving purposes in scenarios of high solar generation adoption, using an SOC-constrained Thevenin battery model and accounting for degradation effects. In another study, Zhao et al. [75] examine a hybrid wind-based generation-ESS system for peak-shaving, considering various ESS technologies and configurations. Meanwhile, the role of ESS technologies in the provision of ancillary services to the grid has been studied in [76] by Zou et al. using a profit-maximizing model for ESS. The study discusses the competitiveness of fast-response ESS technologies within the ancillary services market, due to their ability to quickly ramp up and down demand to complement a high penetration of renewable resources. Whereas in [77], Tan et al. present a technical control approach for a wind power-battery ESS system for frequency ancillary services, in which the ESS is used to coordinate the wind power system for frequency ancillary service purposes.

4.1.2 Integration of Electric Vehicles into the Smart Grid

Transition towards electric mobility in the transportation sector has introduced EVs as a novel DER technology with the potential to be incorporated into the smart grid framework. Specifically, EVs may be integrated via one of three operational modes:

i. Fixed loads (Uncontrolled charging strategy)

ii. Flexible loads (Controlled or smart charging strategy)

iii. Mobile energy storage systems (Vehicle-to-grid)

Considering EVs as fixed loads, significant penetration of EVs into the automotive market will place additional consumption strain onto the power grid due to the aggregate charging behavior of EVs. EV charging will contribute to increasing both the overall electrical demand as well as the peak demand of the grid, which requires the installation of additional reserve generation capacities. Alternatively, EV fleet charging demands may be considered as flexible loads, which allows them to participate in DR programs and engage in controlled or smart charging behaviors. In contrast to uncontrolled charging, projections made by Verzijlbergh et al. [64] have shown that scheduled or smart charging strategies contribute to suppressing the peaking power demand of aggregate EV charging demand. Lastly, the energy storage capacities of EVs can serve as mobile energy storage elements within a smart grid context, alleviating the need for significant adoption of other ESS. Moreover, sufficient integration of electric mobility technologies may enable additional vehicle-to-grid (V2G) services, which provide improved flexibility and reliability for the power grid through bi-directional power flow between EVs and the grid. As discussed in [42] and [41] by Kempton et al., V2G may be employed to provide baseload power, peak power, spinning reserve services, or power quality regulation services. However, with the consideration of accelerated battery degradation effects of V2G battery cycling, the main avenue for economically feasible V2G implementation in the near-term is the provision of ancillary services.

From the results of previous studies considering the integration of EVs, the potential impacts of uncontrolled charging demand are generally well-understood. As an example, a study presented by Akhavan-Rezai et al. [32] discusses the potential impacts of various market penetrations scenarios of EV fleets on the Canadian distribution grid. Meanwhile, current research efforts in EV integration into smart grids via controlled or smart charging strategies are largely concerned with the operational benefits of such strategies under different contexts. In [62], Weis et al. explore the economic advantages of controlled charging strategies in comparison to uncontrolled charging under a New York, USA context. Their study indicates that controlled charging strategies reduce the necessary plant construction for generation capacity expansion through peak demand reduction, as well as having the potential to provide support for renewable generation integration. On this last point, EV fleet charging can be controlled to complement the intermittent nature of renewable generation resources by acting as flexible loads. This is further elaborated on by Mwasilu et al. in [78], which reviews the literature on the interactions between EV fleet charging and renewable resources within a smart grid context. Additional benefits of controlled charging strategies include operational cost and emission reduction, achieved through charge scheduling to periods with lower electricity costs or to those employing a less emission-intensive mix of generation resources. These benefits are explored in [79] by Weis et al. and in [63] by Hoehne et al. In these studies, the role of EV fleets as mobile energy storage capacities have also been considered to further enhance the operational benefits of EVs through V2G capabilities. However, both studies do not account for the effect of limited charging infrastructure on the feasibility of the proposed operational modes.

Further extending the operational flexibility offered by smart EV fleet charging strategies, the potential of bi-directional power flow between EV fleets and the power grid transforms EVs into active elements within smart grids. As proposed by Kempton et al. in [42], the complementary characteristics of EV fleets and the power grid encourages the use of EVs as effective distributed energy storage capacities. This is motivated by the long parking periods expected of EVs, as well as their capacity to generate and store electricity. While this concept is not yet mature, several studies have been conducted to investigate the various potential applications of V2G technology. In [45], Tarroja et al. discusses the key characteristics that differentiate EVs from stationary ESS considering V2G technology, noting the limitations imposed on V2G capabilities by the availability of charging infrastructure. Sarabi et al. [80] considered scenarios of V2G adoption with home and workplace cases, with the incorporation of uncertainties in EV availability. The study also recognizes that the availability of V2G infrastructure should be accounted for in considering feasible V2G implementation. Meanwhile, the potential for EV fleets to support islanded operation of microgrid systems is discussed in [81] by Rodrigues et al., which indicates that V2G could potentially be used to support islanded microgrid systems. A common assumption of these studies, however, is that there is sufficient charging infrastructure available to facilitate the scenarios considered. While this is reasonable for low EV market penetration scenarios, significant market shift towards electric mobility in the future requires that the impacts and characteristics of limited charging infrastructure to be taken into account when considering EVs in a smart grid context.

4.1.3 Contributions of this Work

In this paper, the role of charging infrastructure in serving as the interlinkage between EV fleets and a campus microgrid is investigated. In this effort, this work presents a multi-component simulation approach to forecast the optimal system operation considering varying levels of EV and charging infrastructure adoption. This work also develops upon the energy hub model in [14] to account for the role of EV fleets as energy storage components within the smart grid. The simulation approach is then applied to a case study of the Wilfrid Laurier University campus system in Waterloo, Ontario. From the results of the case study, discussion is made on the applicability of different EV operational modes within smart grids, as well as on the potential impacts of limitations in charging infrastructure on these operational modes.

The contents of this paper are structured as follows: in section 2, the modelling, simulation, and optimization approach employed in this work is detailed, the results of this work and relevant analysis are presented in section 3, and concluding remarks are made in section 4.

4.2 Methodology

In this work, a multi-component approach was used to model and optimize the technology configuration and operation of a campus microgrid system with diverse consumption load profiles, distributed generation technologies, energy storage capacities, and EV integration. A holistic representation of this approach is as shown in Figure 4.1. In this approach, building energy simulation was used in combination with metered energy consumption data and known building properties to determine the energy demand loads of buildings. Meanwhile, a stochastic EV fleet simulation model based on realistic EV parameters was used to determine the charging requirements of a projected EV fleet. These energy requirements were then fed into an energy hub model, which was used to simulate the optimal dispatch of energy vectors within the overall system to reflect optimized system operation, under different energy technology configuration scenarios. Through this approach, this work develops the energy hub model discussed in [23] to incorporate

EV fleets as an aggregate mobile electrical energy storage system (ESS), which is applied to evaluate the potential impact factors of EV integration into a smart grid context. These include the operating costs of the system configuration, its operational GHG emissions, the ability of the implemented system configuration to satisfy the charging needs of the EV fleet, as well as the impacts of EV implementation on the cycling experienced by local ESS capacities for cost optimization.

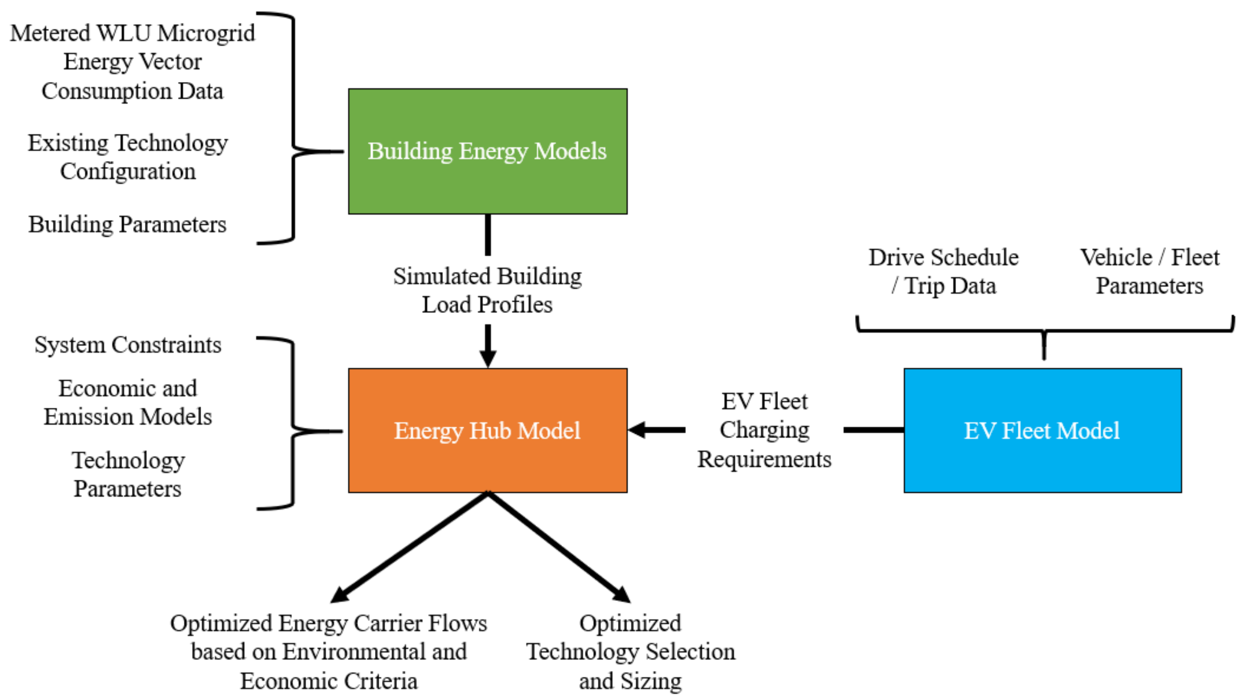


Figure 4.1: Holistic representation of multi-component simulation approach.

4.2.1 Energy Hub Model

The energy hub model used in this work can be understood as an energy balance expressed as shown in (1). Specifically, the energy hub model employs a mathematical approach to consider energy vector coupling for a multi-energy vector system. Here, the various energy consumption requirements of a system are represented in relation to its energy conversion technology efficiencies, inflow of energy vectors from external sources, and energy storage capacities. A time-independent coupling matrix was considered to represent steady-state efficiencies, because it was assumed that transient behavior in energy conversion systems occur in a much smaller timescale than the simulated 1-hour timesteps, and does not significantly affect the expected behavior of the system. Moreover, capacity limitations for energy conversion technologies are represented by constraints on inflow rates of energy vectors, as expressed in (2).

$$D_i(t) = C_{ij}F_j(t) \tag{1}$$

Where: $D_i(t)$ is the set of energy vector demands of size i of the energy hub for timestep t
C_{ij} is the coupling matrix for feed energy vector j to demand i
$F_j(t)$ is the set of energy vector feeds of size j into the energy hub for timestep t

$$F_{j,min} \leq F_j(t) \leq F_{j,max} \tag{2}$$

Where: $F_{j,min}$ is the minimum flow capacity for the feed energy vector j
$F_{j,max}$ is the maximum flow capacity for the feed energy vector j

Energy storage capacities within the system are modelled as shown in (3) and are constrained by capacity and energy flow limitations as shown in (4), (7), and (6). The state of charge of each ESS are determined via a discrete backwards-difference method as shown in (7), which accounts for charging and discharging efficiencies of the ESS as well as standby losses.

$$Q_{k,stor}(t) = Q_{k,in}(t) \cdot \varepsilon_{k,in} - \frac{Q_{k,out}(t)}{\varepsilon_{k,out}} \tag{3}$$

Where: $Q_{k,stor}(t)$ is the net energy vector flow into energy storage system k for timestep t
$Q_{k,in}(t), Q_{k,out}(t)$ are the inflow and outflow of energy vector into the energy storage system k, respectively, for timestep t
$\varepsilon_{k,in}$, $\varepsilon_{k,out}$ are the energy vector inflow and outflow efficiencies for energy storage system k, respectively

$$Q_{k,in,min} \leq Q_{k,in}(t) \leq Q_{k,in,max} \tag{4}$$

Where: $Q_{k,in,min}$ is the minimum inflow rate of energy vectors into energy storage system k
$Q_{k,in,max}$ is the maximum inflow rate of energy vectors into energy storage system k

$$Q_{k,out,min} \leq Q_{k,out}(t) \leq Q_{k,out,max} \tag{5}$$

Where: $Q_{k,out,min}$ is the minimum outflow rate of energy vectors into energy storage system k
$Q_{k,out,max}$ is the maximum outflow rate of energy vectors into energy storage system k

$$SoC_{k,min} \leq SoC_k(t) \leq SoC_{k,max} \tag{6}$$

Where: $SoC_k(t)$ is the state-of-charge of storage system k at timestep t
$SoC_{k,min}$ is the minimum charge capacity of the storage system k
$SoC_{k,max}$ is the maximum charge capacity of the storage system k

$$SoC_k(t) = SoC_k(t-1) + \frac{Q_{k,stor}(t)}{E_{max,k}} - SoC_{k,loss}(t) \tag{7}$$

Where: $SoC_k(t-1)$ is the state-of-charge of the storage system k at timestep $t-1$
$E_{max,k}$is the maximum storage capacity of storage system k
$SoC_{k,loss}(t)$ is the standby loss incurred by the storage system k at timestep t

Meanwhile, EV acting as mobile energy storage components in the energy hub are modelled similar to ESS, but are subject to unique temporal constraints to reflect vehicle availability and charging infrastructural constraints. Specifically, additional time-variant power flow constraints to EVs have been imposed such that power flows are nonzero only during periods in which EVs are not driving and are connected to a charging station. These constraints are similar in form to (4) and (5). EVs also experience capacity losses due to driving, as well as stochastic availability to the energy hub as storage capacities due to user behavior. As such, additional EV-unique constraints have been developed in the energy hub model for the EV fleet components to reflect these factors, which ensures that EVs adequately charge during charging session to satisfy driving requirements for subsequent trips. These are as expressed in (8).

$$Q_{PEV,stor}(t) = Q_{PEV,charge}(t) \cdot \varepsilon_{PEV,charge} - \frac{Q_{PEV,discharge}(t)}{\varepsilon_{PEV,discharge}} - \dot{E}_{PEV,loss}(t) \tag{8}$$

Where: $Q_{PEV,stor}(t)$ is the net flow of electricity into the EV fleet for timestep t
$Q_{PEV,charge}(t)$, $Q_{PEV,discharge}(t)$ are the power charged to and discharged from the EV fleet, respectively, for timestep t
$\varepsilon_{PEV,charge}$, $\varepsilon_{PEV,discharge}$ are the charge and discharge efficiencies for the EV fleet, respectively
$E_{PEV,loss}(t)$ is the loss of stored electricity due to driving for the EV fleet for timestep t

Finally, the overall model can be formulated as a mixed-integer problem (MIP) as expressed in (9), which is implemented via the GAMS platform. This model was then solved using the commercial CPLEX solver based on an economic objective function in order to reflect optimal operation of the energy hub configuration. The objective function is as expressed in (10). A visualization of the developed energy hub model is as shown in Figure 4.2.

$$D_i(t) = C_{ij}F_j(t) + Q_{k,stor}(t) + Q_{PEV,stor}(t) \tag{9}$$

$$Z = Cost_{op} + Cost_{fuel} \tag{10}$$

Where: Z is the overall objective function
$Cost_{op}$ is the annual operating costs of the system
$Cost_{fuel}$ is the annual fuel costs of the system

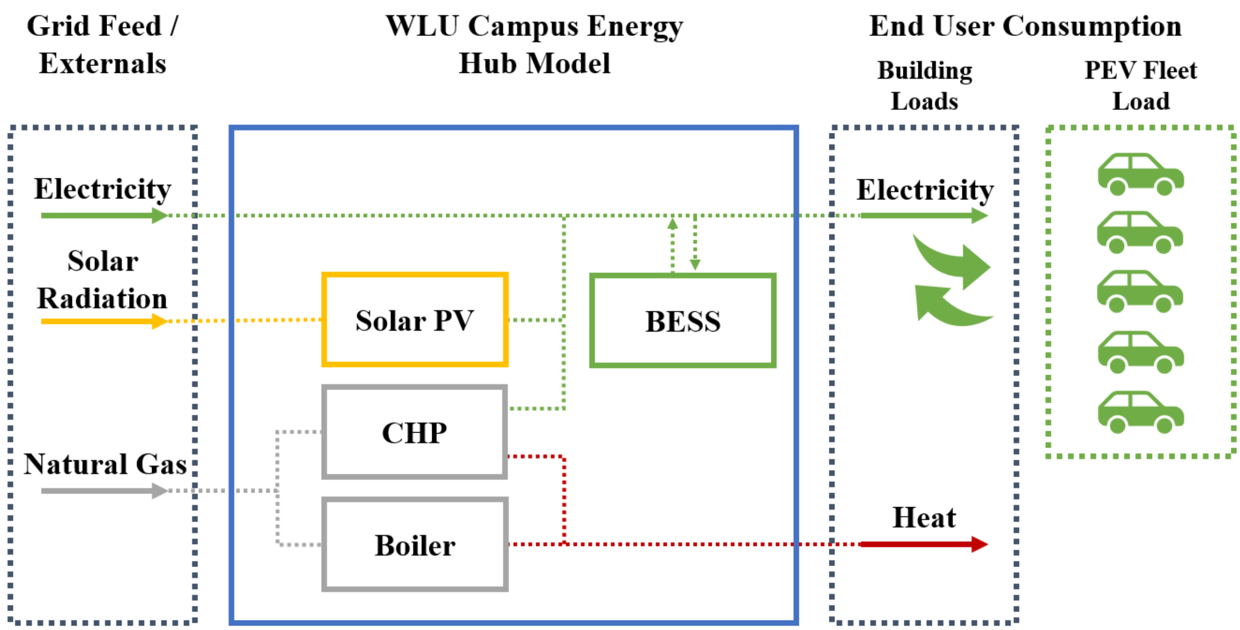


Figure 4.2: Holistic representation of energy hub model.

4.2.2 Monte Carlo Simulation of Electric Vehicle Fleet Charging Demand

A Monte Carlo simulation was used to generate probabilistic scenarios of EV fleet charging demands considering distributions of EV vehicle battery capacities, trip arrival times, departure times, daily driving requirements, and minimum required state-of-charge (SOC) of the vehicle. In considering these factors, the simulation develops realistic EV fleet charging behavior that account for variations in vehicle characteristics and driver behavior. An illustration of this simulation approach is as shown in Figure 4.3.

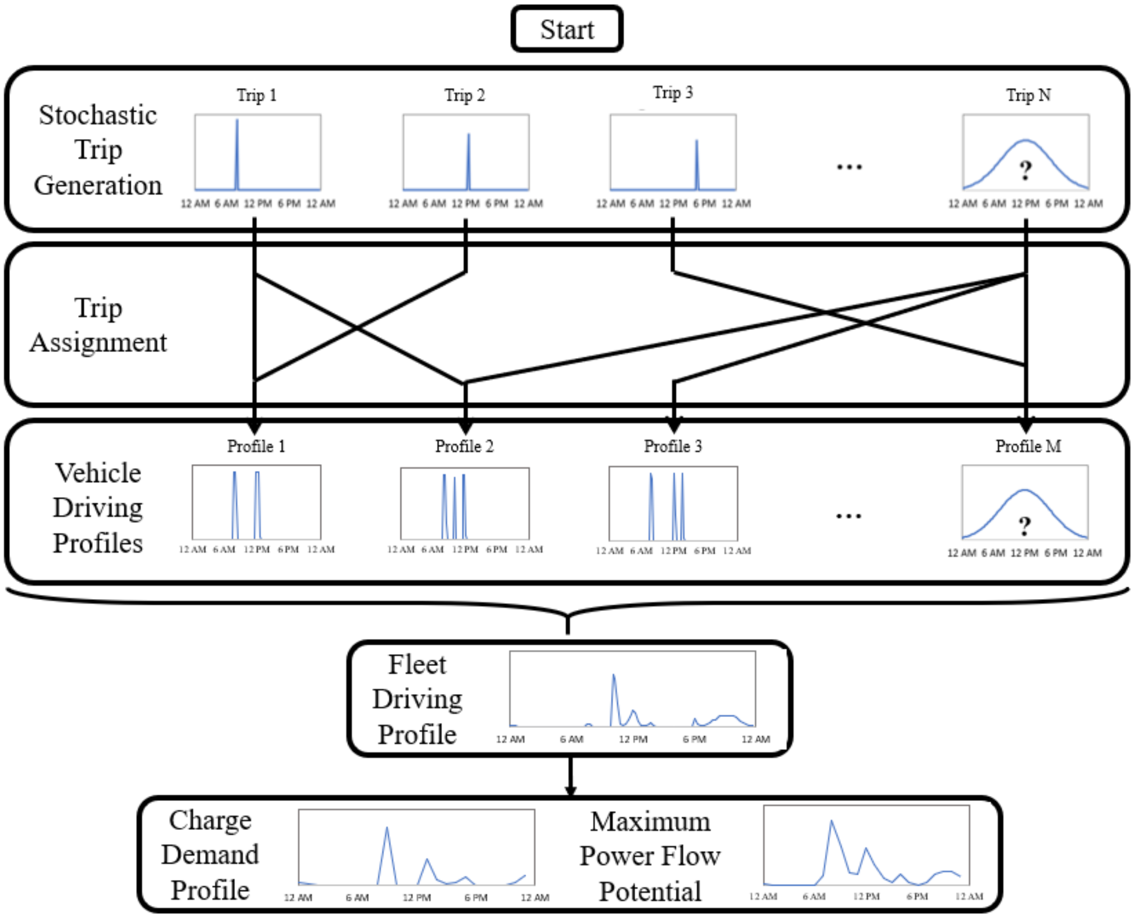


Figure 4.3: Flow chart of Monte Carlo simulation for EV fleet charging demand.

4.2.3 Case Study – Wilfrid Laurier University Campus Microgrid

The Wilfrid Laurier University campus in the Waterloo, Ontario region consists of over 35 buildings with a diverse mix of energy consumption behavior. The buildings consist of residential, commercial, research and academic, athletic, and administrative types and are used to service over 16,000 students. As a part of its Laurier Energy Efficiency Program, Laurier aims to incorporate DER within the campus with the objective of establishing a microgrid system. This includes the installation of rooftop solar arrays for ~500 kW of renewable generation, a 1,994 kW(e) natural gas generator for distributed generation, and an on-site battery ESS for 6 MWh of energy storage capacity.

As the object of this study, 8 buildings were selected which reflected the diverse mix of energy consumption behavior of the Laurier campus. The selected buildings are as indicated on the Laurier map as shown in Figure 4.4. The heating and electrical energy consumption data were metered and data collected over the 2016 – 2017 period were used to create representative energy models of the buildings via the TRNSYS software, considering the present HVAC and energy conversion technologies in each of the buildings. A summary of the building characteristics and simulated heating and electrical consumption loads can be found in Table 4.1.

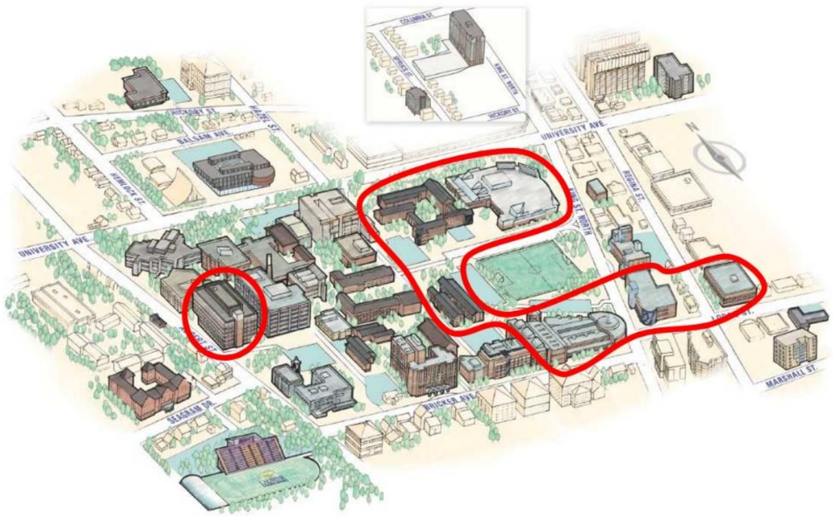


Figure 4.4: Map of Laurier campus. Only the highlighted buildings were considered in the case study.

Table 4.1: Summary of building characteristics and energy consumption loads of buildings considered in case study.

Building (Type)	Total Conditioned Floor Area (m^2)	Total Conditioned Volume (m^3)	Heating Demand (MWh/yr)	Electricity Demand (MWh/yr)
Athletic (Athletic)	12,105	36,390	2,470.24	1,853.52
Clara Conrad (Residential)	7,500	20,018	1,481.60	313.10
Willison (Residential)	6,132	16,693	1,222.35	283.18
Library (Academic)	9,700	30,443	4,120.65	930.34
Science (Academic)	14,778	43,013	4,061.60	2,538.10
Science Research (Research)	3,996	11,868	291.06	1,085.01
202 Regina (Commercial)	7,337	21,790	406.09	763.15
Career and Coop (Commercial)	2,369	7,041	294.63	254.88

As for the characteristics and behaviors of the EV fleet considered for the case study, the aforementioned Monte Carlo simulation approach was used to project a hypothetical fleet of 250 EVs that is reflective of light-duty vehicles used for workplace commutes, considering a market penetration of approximately 25%. Here, vehicles travel on average 50 km/day as according to

National Transportation Statistics [82] and participate in charging throughout the workday. The charging behavior for this fleet are reflective of workplace commuting, occasional lunchtime driving, and a small amount of sporadic driving throughout the workday. As well, a small fleet of 50 EVs were simulated to reflect campus-owned vehicles, which are used to support campus operations during the day. This fleet was simulated to travel an average of 75 km/day and are expected to engage in nighttime charging. It is noted that such behavior is similar to an above-average fleet of light-duty vehicles that participate solely in home-charging. A representative profile for the resulting uncontrolled charging behavior of the aggregate fleet is as shown in Figure 4.5.

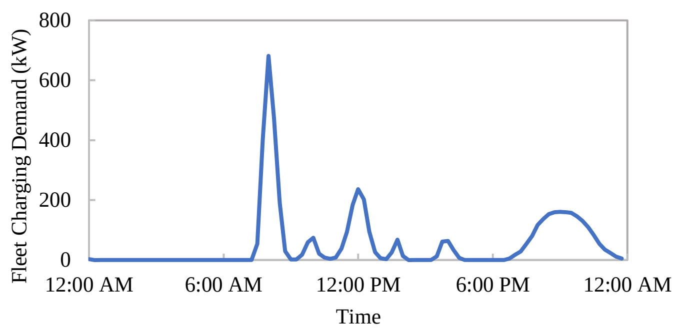


Figure 4.5: Representative uncontrolled charging demand for EV fleet in Laurier case study.

For the evaluation of fuel costs and emissions associated with system operation, Ontario conditions were used. Throughout the annual simulation, the time-of-use (TOU) electricity pricing scheme shown in Figure 4.6 was used to evaluate electricity costs, whereas a constant rate of 0.0308 $CDN/kWh was used for natural gas costs [38, 39]. Meanwhile, a daily emission factor schedule was used to evaluate emissions associated with grid electricity consumption, based on an average daily schedule of Ontario generation resource mixes, while natural gas consumption incurred a constant emission factor of 525 g GHG/kWh [40, 41].

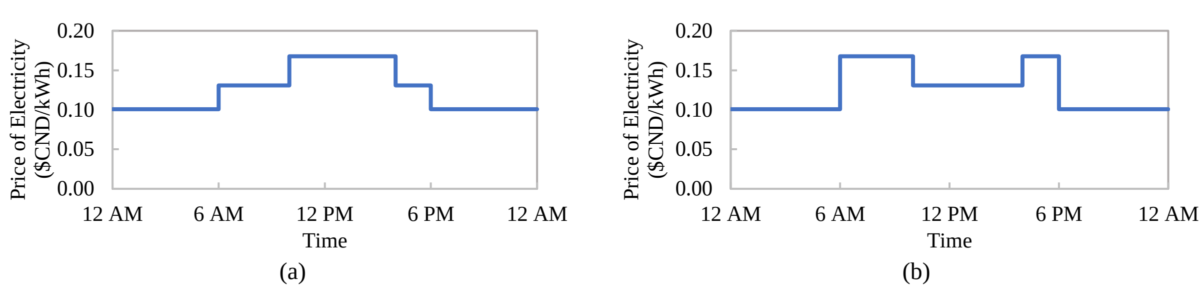


Figure 4.6: Time-of-use pricing scheme for electricity costs in Ontario, Canada.

4.2.4 Simulation Scenarios

In this study, the Laurier microgrid system is simulated under various EV operational modes, charging infrastructure availability implementations, and expected plug-in duration scenarios. In terms of the availability of charging infrastructure, both level 2 and DC fast charging rates were considered, as well as varying degrees of charging port sizing. Various levels of expected EV plug-in durations were also considered to anticipate different levels of charging urgency. Lastly, three operational modes for EV integration were considered, including uncontrolled charging behavior, controlled charging strategies, and V2G technology. A summary of simulation parameters considered is as shown in Table 4.2.

Table 4.2: Summary of simulation parameters and range of values considered in case study.

Parameter	Ranges Considered
Operational Mode	• Uncontrolled Charging • Controlled Charging • V2G
Charging Rate (kW)	• Level 2, Charging (6.6) • DC Fast Charging (66)
Infrastructure Availability (# of Charging Ports)	0 – 300
Plug-in duration (Hours)	0 – 4

4.3 Results and Analysis

4.3.1 Effect of Charging Infrastructure Limitations on EV Adoption and Feasibility of EV Operational Modes

Limited availability of charging infrastructure reduces the maximum possible power flow to and from the EV fleet. As a result, the potential of the implemented EV fleet operational mode may not be fully realized. In the worst case, EVs may not receive adequate charging to maintain their primary transportation function, which acts as a disincentive against EV adoption. Such consequences mainly manifest from the implementation of charging infrastructure, such as in the sizing of charging ports or in the selection of the charging rate. To demonstrate, results from the Laurier case study considering scenarios of insufficient charging infrastructure availability are as shown in Figure 4.7.

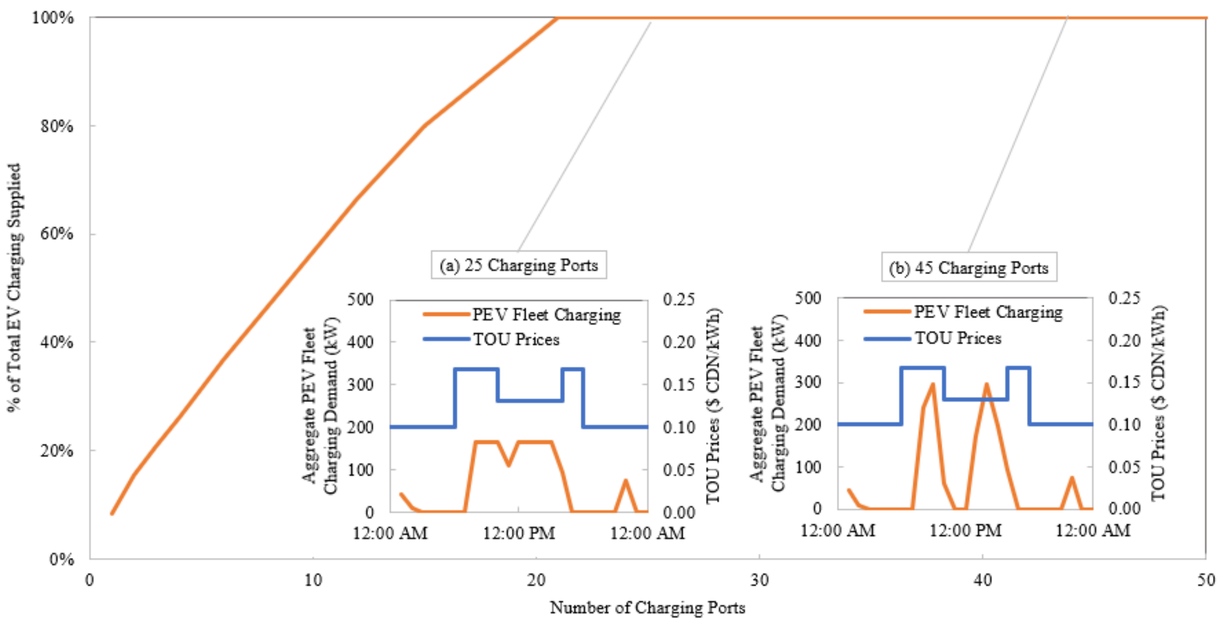


Figure 4.7: Charging delivered to EV fleet with increasing availability of charging infrastructure. EV fleet charging profiles are shown for (a) 25 charging ports and (b) 45 charging ports.

As observed from Figure 4.7, when considering charging infrastructure implementations that are inadequate for EV adoption, the amount of charging that can be provided to the EV fleet is insufficient to meet EV driving needs. The amount of required EV charging that is met increases with respect to increasing charging infrastructure. In the figure, this is represented by increasing the number of charging ports available to the EV fleet. The initial behavior is indicative of insufficient charging infrastructure and continues until a critical number of charging ports are available, which represents the minimum degree of charging infrastructure implementation required to accommodate adoption of a certain fleet size of EVs. This minimum degree of charging infrastructure is a critical point under which the charging needs of the EV fleet will not be fully met, and it is dependent on various parameters of the projected EV fleet such as fleet size, expected plug-in duration, driving behavior, and coincidence with other vehicles' charging schedules. Beyond this critical point, any additional installation of charging ports only serves to increase the maximum power flow to and from the EV fleet, thereby increasing the resiliency of the implementation against charging demand uncertainties, as well as increasing its ability to address peak charging demands. These effects are considered by increasing the number of charging ports beyond the minimum required amount to satisfy EV charging. A comparison of the difference in peak charging behavior is as shown in Figure 4.7 for simulated scenarios considering 25 and 45 charging ports, which are representative of peak-reduced charging behavior due to power flow limitations and a less limited scenario. As shown, the 25 charging port scenario constrains maximum EV charging at approximately 200 kW, whereas the 45 charging port scenario does not significantly constrain peak charging, resulting in charging peaks of as high as 300 kW.

In consideration of different EV operational modes, charging infrastructure implementations that are insufficient to serve the primary charging needs of the EV fleet will be similarly inadequate for any additional functionality required for advanced operational modes. In particular, charge-delaying control and bi-directional power flows for controlled charging strategies and V2G, respectively, will not be feasible in such conditions. This is because these services should be considered as secondary in comparison to the primary transportation function of EVs. As such, EV charging behavior will be indifferent to the presence of such capabilities due to the need to satisfy its base charging needs.

4.3.2 Effect of Charging Infrastructure on Uncontrolled Charging Behavior

The primary objective of EV fleets that engage in uncontrolled charging behavior is to meet the immediate charging needs of the fleet. As such, limitations in charging infrastructure impact two properties of this operational mode:

i. Peak charging behavior of the aggregate EV fleet

ii. Queuing and service durations experienced by EVs

It should be noted that these two impacts are not mutually exclusive. Rather, these are effects that manifest concurrently at different degrees of charging infrastructure availability. In the first and more obvious effect, inadequate sizing of charging infrastructure hinders the ability of the system to meet peak EV charging demands, due to its inability to supply the high power flows required. In the second effect, the lack of charging infrastructure to support peak charging demands will result in peak-reduced and prolonged charging, which manifests as charging port queuing. Depending on the characteristics of charging peaks, long queuing durations may inhibit the ability of the EV to perform subsequent driving.

First, the peak-reduced and prolonged charging behavior increases the system’s resiliency against variable electricity pricing and acts to indirectly suppress peaking power demand on the grid. This is because levelized demands are less intermittent and are thus less prone to incurring high charging costs due to incidence with on-peak periods. Reduced peaking behavior is also more manageable by the microgrid system or by the external power grid, requiring less ramping up and down of reserve resources to meet the peaking consumption demand. Again, this is owing to the consistency of levelized charging demand. To demonstrate this point, a comparison of uncontrolled EV charging demand between limited and unlimited charging infrastructure scenarios from the case study is as shown in Figure 4.8. From this graph, it is observed that, in a system subject to TOU electricity pricing, higher costs can be incurred in the unlimited charging infrastructure case due to aggregate charging demand occurring during on-peak periods. Meanwhile, limitations in charging infrastructure mitigates and prolongs these peak demands such that some of the charging demand is satisfied during periods of lower cost. Of course, the opposite could also occur, where peak EV demands occurring during off-peak periods may be prolonged into on-peak periods. The takeaway here, however, is that such behavior should be accounted for when considering uncontrolled charging conditions, in order to optimally design charging infrastructure to complement the operational costs of EV fleet charging.

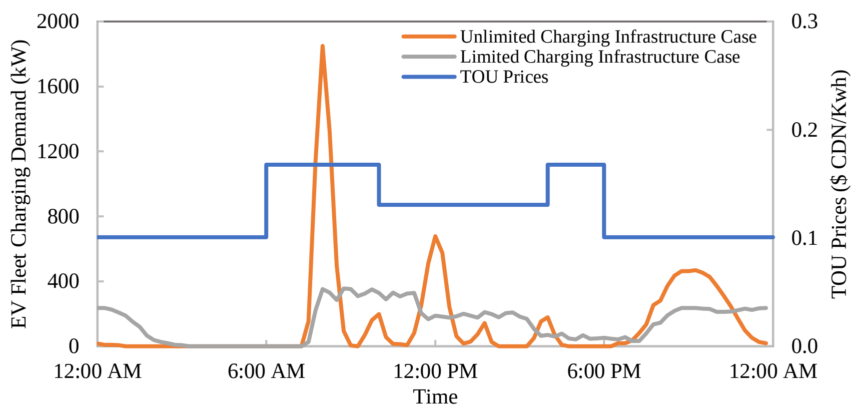


Figure 4.8: Comparison of uncontrolled EV fleet charging demand profiles between limited and unlimited charging infrastructure scenarios.

As for the second impact, long queuing durations for EV charging resulting from prolonged charging act as a disincentive against EV adoption. Practically, this can delay EV availability for subsequent trips. Manifestation of charging port queuing will also require the development and implementation of effective queuing strategies, as well as the infrastructure to coordinate queuing. To demonstrate, the prolonged charging duration effect can be inferred from Figure 4.9. Based on results from the case study, the additional waiting duration required for EVs in charging port queuing to satisfy the same amount of overall EV charging demand increases as the degree of charging infrastructure implementation decreases. This implies that vehicles must be remain in queuing for longer durations in order to meet their charging requirements. This is because, due to the lack of available charging ports, EVs are required to queue for longer durations in order to meet their charging needs. Such effects on queuing duration should be considered when designing charging infrastructure implementations, in order to optimize utility of charging infrastructure to serve user convenience.

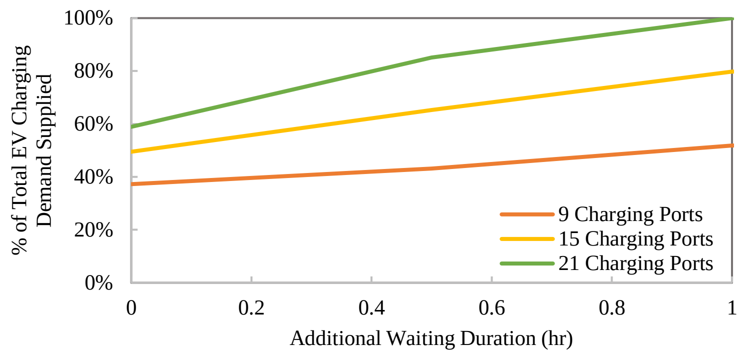


Figure 4.9: Comparison of delivered charging to EV fleet considering different sizing of charging ports.

4.3.3 Effect of Charging Infrastructure on Controlled Charging Behavior

Building on the benefits discussed in the previous section, controlled or smart charging is an operational mode that aims to derive operational benefits from EV charging via control of EVs as flexible loads. In this regard, the impact of limited charging infrastructure on controlled or smart charging strategies affects the following three properties:

i. Resiliency of controlled charging strategies against charging demand uncertainties

ii. Charge delaying potential

iii. Degree of interaction with stationary ESS

Following from the discussion on the feasibility of controlled charging strategies under limited charging infrastructure implementation, inadequate availability of charging infrastructure invalidates the operational feasibility of controlled charging strategies. The potential for controlled charging strategies become apparent, however, once excess charging infrastructure is installed and the immediacy for EV charging becomes less urgent. Once these conditions are met, increasing availability of charging infrastructure will provide increasing flexibility and resiliency for controlled EV charging to achieve operational benefits, without impeding the EVs' primary function. Additionally, adoption of controlled charging strategies within a smart grid context creates a beneficial interaction between EV fleets and stationary ESS capacities. In comparison to uncontrolled charging behavior, controlled charging strategies alleviate cycling experienced by stationary ESS for operational cost optimization. This is because stationary ESS are required in a lesser capacity for load balancing purposes, since controlled EV charging can be leveraged to achieve similar results.

In order to contextualize these impacts, results from the case study are used to illustrate the effect of limited charging infrastructure on the controlled charging operational mode. As shown in Figure 4.10, the controlled charging behaviors for both limited and unlimited charging infrastructure cases are compared considering charging cost optimization based on TOU electricity prices. As shown, limitations in charging infrastructure reduce the ability of the EV fleet to function as a flexible load. In one effect, charging is incurred during on-peak periods because charge-delaying would result in significant queuing. In another, limitations on maximum charging rates result in some charging demand being delayed beyond optimum charging periods. Both effects reduce the potential of controlled charging strategies for cost-optimized charging. Consequently, limitations on charging infrastructure also reduces the resiliency of controlled charging strategies against unanticipated charging demands, since inflexible charging behavior is less adaptable to unanticipated demands.

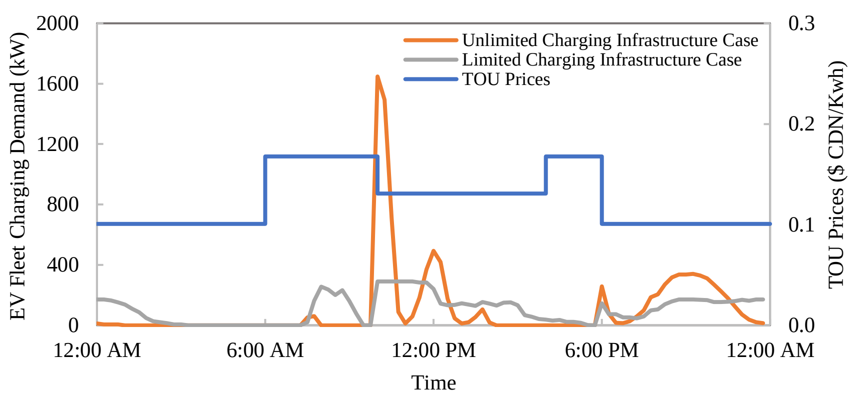


Figure 4.10: Comparison of controlled EV fleet charging demand profiles between limited and unlimited charging infrastructure scenarios.

Also demonstrated in the case study, the cycling demand experienced by the stationary ESS was shown to decrease with respect to increasing charging infrastructure and increasing allowable queuing duration. This is illustrated in Figure 4.11(a). One conclusion to be drawn from this is that appropriate implementation of controlled charging strategies mitigates the cycling demand experienced by stationary ESS capacities, reducing cycling degradation and the required sizing of such capacities. However, this is accommodated only by sufficient charging infrastructure and EV charging behaviors, since the charging needs of the EV fleet would be not be fully met otherwise. As shown in Figure 4.11(a), both increasing degrees of charging infrastructure availability and allowable queuing durations, beyond those required to meet the charging needs of the fleet, reduce cycling of stationary ESS for charging cost optimization. This is because much of the load-balancing operation is substituted by controlled charging. It should be noted, however, that short plug-in durations for EVs do not significantly alleviate load-balancing cycling experienced by the stationary ESS, despite increasing charging infrastructure availability. This is because of the behavior of aggregate EV charging and its interaction with the TOU electricity pricing scheme considered in the case study. Since the plug-in duration of the EV charging behavior is short and is coincident with on-peak periods, the EV fleet is not able to access low TOU electricity rates, thus becoming reliant on stationary ESS support for optimizing charging costs. As a general takeaway, this suggests that controlled charging strategies for TOU cost optimization should account for the expected plug-in behavior of the target EV fleet, since it can impact both the optimal charging infrastructure implementation as well as the operation of supporting ESS. Similarly, it is also demonstrated that controlled charging strategies are more operationally economical in systems without any ESS capacities. This is largely due to the derived benefits of charging cost optimization from charge-delaying control of EV fleet charging. An illustration of this effect from case study results is as shown in Figure 4.11(b), for scenarios varying in charging port sizing and allowable queuing durations at charging ports.

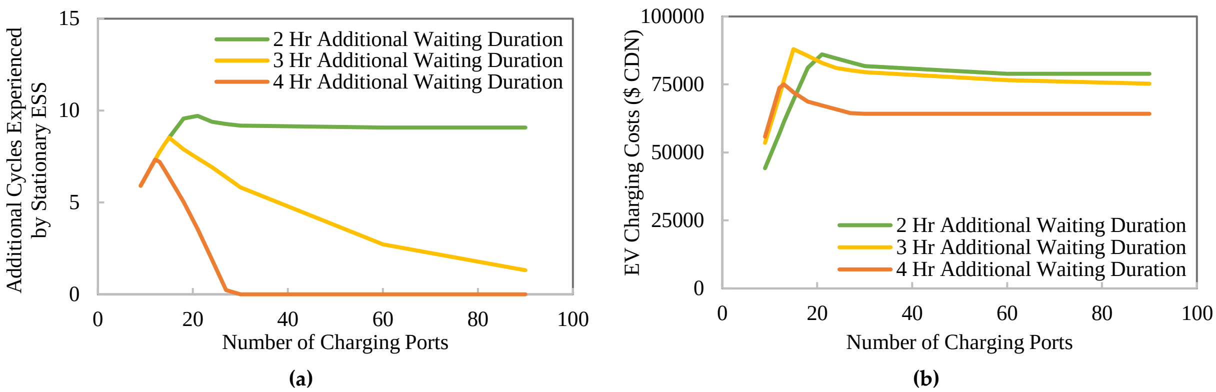


Figure 4.11: Comparison of (a) additional cycling imposed on stationary ESS and (b) additional operating costs imposed on microgrid system by EV fleet between different scenarios of allowable queuing duration.

4.3.4 Effect of Charging Infrastructure on V2G

The V2G operational mode utilizes bi-directional power flow capabilities in order to transform EVs into mobile energy storage capacities, which can potentially displace the need for stationary ESS installation. Considering their role in enabling bi-directional power flow, limitations in charging infrastructure impact the following three properties of the V2G operational mode:

i. Resiliency of V2G operation against charging demand uncertainties

ii. Potential of V2G for fast response

iii. Displacement of cycling experienced by stationary battery ESS

Similar to the feasibility of controlled charging strategies, the success of V2G is dependent on the availability of charging infrastructure. In one extreme, unlimited power flows in charging ports allow full accessibility of EV energy storage capacities for V2G purposes. In the other, constrained power flows to and from EV fleets limit the amount of charging and discharging possible, thus mitigating the potential benefits of V2G implementation. Between these two extreme conditions, several factors emerge that affect the success of V2G implementation. Considering the first impact listed above, limitations in power flow and availability of charging infrastructure for EV fleets reduce the resiliency of V2G implementation against uncertainties in EV demands. Extending from the discussion on controlled charging, low power flow rates and low availability of charging ports constraint the degree to which V2G may be employed, thereby reducing the flexibility of V2G services. Moreover, this effect is magnified for V2G services since V2G participation depletes EV capacities, which directly competes against the primary transportation function of EVs. Consequently, the resiliency of V2G against uncertain EV fleet demands is also reduced, since inflexible V2G operation is less adaptable to uncertain EV behavior, especially considering the competitive interactions between V2G and EV driving. Reasonably, this impact will manifest as an SOC constraint, in which V2G services cannot be performed by EVs with SOCs under a certain threshold, in order to mitigate the potential for V2G participation to affect EV driving due to uncertainty. Of course, this threshold decreases the accessible ESS capacity for V2G, thus indirectly reducing the overall functionality of EV fleets as mobile ESS capacities.

Limitations in charging infrastructure also has a more direct impact on the success of V2G, which is as described by the second impact. In this effect, limitations in charging infrastructure effectively reduces the available ESS capacity and the power flow potential for V2G. Specifically, the sizing of charging infrastructure limits the portion of total EV fleet capacity that is accessible for V2G, while charging rate constraints limit the power flow potential of the EV fleet for the provision of fast response services. Finally, the last impact concerns the interaction between V2G technology and stationary ESS. As discussed, sufficient integration of EVs within the smart grid as mobile ESS elements can potentially reduce or eliminate the need for stationary ESS. However, since the effective capacity and maximal power flow to and from the EV fleet is defined by the characteristics of charging infrastructure, the potential of the EV fleet to displace stationary ESS capacities is dependent on the implementation of charging infrastructure.

Based on the results of the case study, the impact of charging infrastructure limitations on the feasibility of V2G implementation can be inferred from Figure 4.12. The figures show that, considering increasing implementation of charging infrastructure, the cycling experienced by stationary ESS for load-balancing decreases. Within the case study, this is explored considering varying charging port sizing and different durations of plug-in periods for EVs, as well as two levels of charging rates. When considering a level 2 charging rate scenario, Figure 4.12(a) indicates clear limitations for V2G operation due to the power flow constraints imposed by the charging rate. With respect to the number of charging ports, it is shown that low sizes of charging infrastructure implementation impose additional cycling on stationary ESS capacities to provide support for cost-optimal operation, these are indicated by a negative amount of cycling alleviated from stationary ESS, which corresponds to additional cycling. Despite reasonable implementation of excess charging ports, it is still observed that V2G fails to alleviate cycling from stationary ESS for short plug-in durations. This is because, while charging port availability may not limit V2G participation, the potential of V2G is constrained by two additional factors.

First, limited connectivity of EVs to the grid reduce their potential to provide V2G services. In comparison to stationary ESS, EVs are only connected to the grid via charging infrastructure, which is subject to competition for vehicle charging needs. Moreover, EVs must remain connected to the grid for a sufficient duration in order to perform load balancing services, in addition to the plug-in duration required to meet its own charging needs. Secondly, low power flow capabilities for charging infrastructure limit the rate at which EVs may inject power into the grid. This further hinders the operational potential of V2G by limiting the maximum amount of charge cycling that is possible. The effects of such limitations are demonstrated in the level 2 charging rate case, in which V2G is only able to successfully offset stationary ESS capacity cycling considering long EV plug-in durations and significant excess charging port sizing. In contrast, scenarios considering implementation of DC fast charging for V2G operation were able to displace significant cycling from stationary ESS. As shown in Figure 4.12(b), the high power flow rates considered in the DC fast charging scenarios improve the potential of V2G operation for fast response, displacing cycling experienced by the stationary ESS by up to 74%. Simultaneously, higher power flows lower the expected durations of connectivity for EVs for V2G participation and fewer numbers of charging ports is necessary.

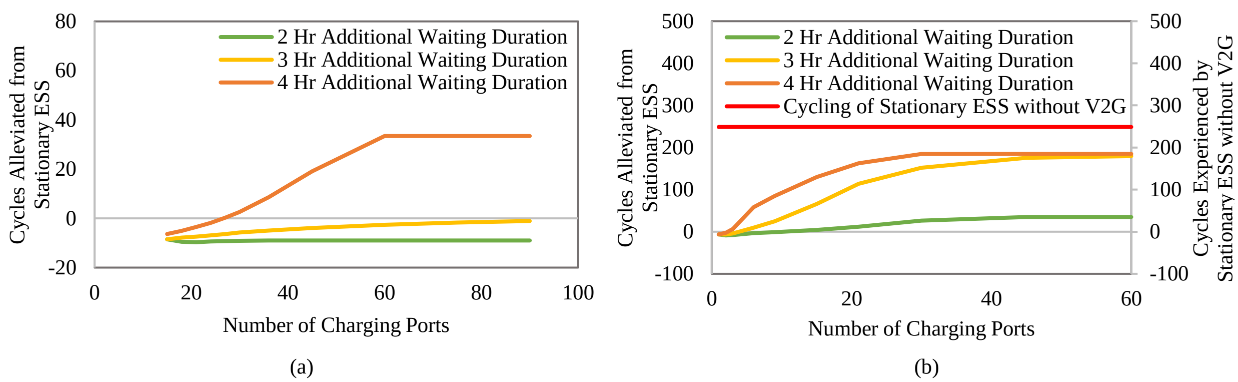


Figure 4.12: Cycling for load balancing alleviated from stationary ESS by V2G operation considering (a) level 2 and (b) DC fast charging rate limitation.

From these results, it has been shown that the feasibility of V2G operation is highly dependent on the rate of power injection from EVs, as well as the connectivity of EVs to the grid. Specifically, the case study shows that charging infrastructure with level 2 charging rates are insufficient to support V2G operation considering reasonable durations of grid connectivity for participating EVs. More generally however, the results indicate that, in order to effectively displace stationary ESS capacities, charging infrastructure implementation for V2G operation must emulate the availability and fast response capabilities of existing stationary ESS technologies.

Chapter 5 Conclusions and Recommendations for Future Work

5.1 Summary and Conclusions

Recent popularization and development of distributed renewable energy sources (RES) and electric vehicle (EV) technologies, along with worldwide pressures to transition towards a more sustainable energy future, have led to the conceptualization of smart energy systems as a framework for incorporating such disruptive technologies into the existing energy infrastructure. Within this concept, various energy generation, conversion, and storage technologies are proposed to operate cooperatively via advanced communication and information technology, in order to optimize the overall energy utilization, reliability, and security of future energy systems. Successful implementation of this concept, however, have yet to be realized in a real, large-scale system. As such, there is a strong research need to search for optimal planning, implementation, and operational characteristics of future smart energy systems in order to ensure the viability of this concept, as well as to most efficiently facilitate the transition towards a sustainable energy future.

In this thesis, two contributions to the literature have been presented. Firstly, in the work presented in Chapter 3, the cooperative operation of buildings of complementary usage behaviors was examined via economic, environmental, and energy efficiency perspectives. Most importantly, the work quantifies the relative benefits of employing the energy hub concept in comparison to independent building operation for an energy system containing commercial and residential components. Specifically, the economic and environmental benefits of adopting principles for coordinated energy vector dispatch within mixed residential and commercial hubs are reductions in annual operating costs and emissions of 61.2% and 1.29%, respectively. Meanwhile, the local system also becomes less reliant on BESS capacities for regulation and on grid-derived generation for electricity, corresponding to reductions in capacity and consumed generation of 6.7% and 13.8%, respectively. Moreover, the viability of different distributed generation technology configurations was considered in several scenarios for a case study under an Ontario, Canada context. In this aspect, the study has affirmed the feasibility of the smart energy system concept at the building level and have provided insights into the design of effective RES integration strategies within mixed commercial and residential hubs.

In the second work, presented in Chapter 4, the impacts of charging infrastructure on EV adoption and its role in facilitating the integration of EV fleets as grid components was examined from an energy hub perspective. In comparison to existing literature, this work focuses on the planning and design of charging infrastructure in serving as the interlinkage between EV fleets and the power grid. Specifically, the characteristics of charging infrastructure required to facilitate different EV charging modes was analyzed via energy hub modelling and simulation of optimal energy vector dispatch. The results of this work have provided insights into the viability of advanced EV charging modes and the relative potential for their implementation into power systems in future smart energy networks. Specifically, the feasibility of controlled/smart charging and V2G modes were found to be dependent on the charging port availability, EV plug-in durations, and maximum power flow characteristics of implemented charging infrastructure. The success of V2G for displacing BESS capacities, then, is limited by the potential of charging infrastructure to emulate the power flow characteristics of stationary BESS systems. These characteristics correspond to high capacity availability and fast response capabilities, as well as maximum power flow limitations well above the those of the current level 2 standard.

Furthermore, this work also presents a development of the energy hub model presented in [23] to incorporate EV fleets as mobile battery energy storage system (BESS) components, as well as an application of this model within a multi-component simulation of energy hub operation with a stochastic EV driving demand model derived from Monte Carlo simulation.

5.2 Recommendations for Future Work

The following recommendations and research directions are proposed for future work:

1. Additional quantitative work for smart energy system operation may be conducted for more complex systems. Particularly for energy hubs containing end-users with a variety of energy consumption behaviors and a wide mix of distributed grid components, there is opportunity for more significant advantages for smart energy systems. Moreover, determination of the financial conditions to facilitate the implementation of smart energy systems with generalized configurations may provide insights for policy-makers, which contributes to accelerating the transition towards future energy systems.

2. There is potential for the integration of an agent-based model for EV driving behaviors with the developed energy hub model, which can capture more realistic interactions between the transport sector and advanced energy networks. Moreover, simulation of the interactions of different zero-emission vehicle types with a multi-energy vector system may provide insights into optimal technology adoption configurations for future energy systems.

3. Financial evaluation of the payback period of advanced charging infrastructure adoption in the near-term may provide incentive for accelerated development of EV infrastructure. Specifically, an operational case study is recommended for a fleet of business- or government-owned EVs that participate in home- or workplace-charging to engage in controlled charging or V2G, in order to evaluate the impact on EV owners' driving behavior and to quantify the operational benefits of these advanced charging modes.

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