Energy Storage for Grid Power:
Policy Arguments Based on Technical, Economic, and Environmental Analysis

by

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AUTHOR'S DECLARATION

This thesis consists of material all of which I authored or co-authored: see Statement of Contributions included in the thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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ABSTRACT

Renewable energy has been increasing as the demand for cleaner energy increases. The introduction of renewable energy into the power grid has however introduced supply and demand discontinuities due to the intermittency of renewables. Energy storage implemented alongside renewables aids in the management of energy as it allows for load shifting of the intermittent energy to optimize its use and better match the supply and demand profiles.

Energy storage can come in many forms such as batteries or Power-to-gas systems. Batteries offer small scale solutions which can be cost effective if repurposed electric vehicle batteries are used. Hydrogen can also be produced using excess electricity which can then be stored or injected into the natural gas grid. Modeling through a MATLAB model of different scales of storage for both batteries and hydrogen demonstrate the economic viability of these projects as well as the environmental impact. Policies are also examined and recommendations made including: ending the Feed-in Tariff program, providing preferential electricity pricing to energy storage projects, and providing an equivalent ethanol subsidy to hydrogen of 79.5 cents per kilogram.

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Chapter 1: INTRODUCTION

The electrical system is integral to the daily lives of the modern society. This makes electricity a necessity for a jurisdiction to function and the economy to prosper. The type of electricity generation that is used, however, has caused contentious debates. Politicians and consumers must now way additional factors such emissions and efficiency in decision making for new power generation projects.

Power generation started with water and coal, producing power either from water flow or steam heated by coal. These methods of producing electricity produced significant emissions produce environmental and health hazards. The Clean Air Task Force has estimated that in 2010, some United States jurisdictions mortality rates that could be attributed to coal power plants per 100,000 persons was greater than 20 people [1]. Coal is also widely known as the biggest emitter for power generation and contains a plethora of other harmful chemicals.

With the knowledge of greenhouse gas emissions and global warming, new power generation sources were needed. Solar and wind have begun to increasingly replace coal and other emitting electricity sources, with coal being phased out of Ontario in 2014 [2]. This has created an overall clean power grid which contains 71% zero or near zero emission power generation sources such as nuclear, hydro, wind, and solar [2].

In Ontario the use of clean, intermittent renewables and nuclear power has caused instability in the jurisdictions of the power grid. This can be seen be examining the Hourly Ontario Electricity Price (HOEP). The non-weighted average electricity price, that is to say not taking into consideration the amount of electricity produced each hour, has an average of approximately $53 per MWh previous to 2009, which drops to $28 per MWh after the introduction of the Feed-in-

Tariff program [3] [4]. This program, part of the Ontario Green Energy Act, provides a contracted price for solar and wind electricity to be added to the grid. These renewable energies are intermittent and do not always create electricity when needed which drives down the market price of electricity. Nuclear power also cannot deviate sufficiently to offset production further driving down market prices. This has caused the price of electricity to be 0 or negative 10.7 and 13.0 percent of the hours in 2014 and 2015 respectively [4]. It has also caused higher maximums, lower minimums, and higher variability, causing the standard deviation to reach a high of 47 in 2014 from a low of 19 only two years earlier [5].

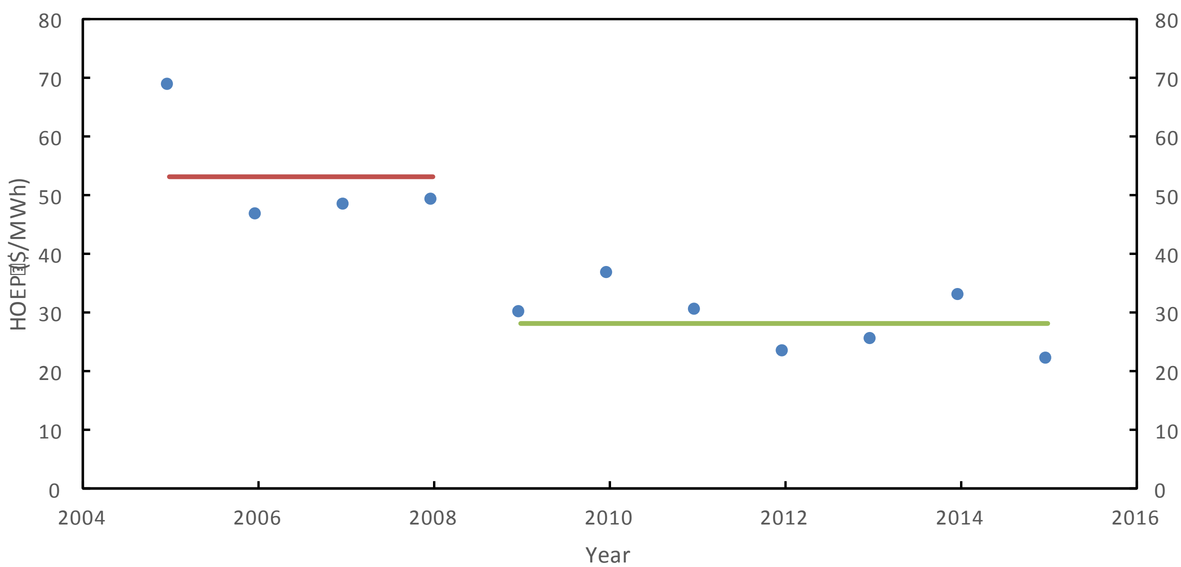

Figure 1: Hourly Ontario Electricity Price with average both before and after introduction of the Feed-in-Tariff program

When the price of electricity is negative, energy is either being wasted or sold to neighboring jurisdictions at a negative price. When the energy is sold at a negative price, it means Ontario is paying the jurisdiction to take the electricity. To offset the losses a Global Adjustment price is calculated and added to the market price. This price is however only paid by customers in the jurisdiction. This is economically unbeneficial to Ontario and may be one of the reasons for the increase in electricity prices.

In order to better match the power generation to demand, energy storage can be implemented into the power grid. This can be in the form of batteries, flywheels, pumped hydro, compressed air, Power-to-gas, and many others. These energy storage projects allow for storage when demand is low and then allows power to be injected into the grid when demand is high. These systems are another tool for a jurisdiction to monitor, control, and optimize the efficiency and the effectiveness of the power grid.

1.1 Scope and Objective of Thesis

In this thesis the author examines different energy storage systems and the accompanying policies that might be required to make them financially viable. This is especially important as authors are demonstrating the technology to be technically viable, however the implementation into the grids can differ between jurisdictions due to plethora of market types and policy each has. This work therefore specifically examines Ontario, Canada for data, analysis, and policy. The objective is to determine policy recommendations that are sustainable, allow for energy storage, and promote renewable and low emitting electricity generation sources to further reduce the greenhouse gas emissions produced by a jurisdiction.

In this thesis the effectiveness of policies or programs are examined through economic, environmental, and technical analysis of energy storage systems. This is conducted on multiple energy storage systems in order to make broad but definitive policy arguments in order to better direct the implementation of energy storage in Ontario.

1.2 Thesis Outline

In this thesis, two different forms of energy storage are examined. In, Chapter 2 batteries for energy storage are examined in the integration of a green energy hub which includes solar and wind power generation. This chapter is used to examine the Feed In-Tariff program in Ontario and the use of repurposed batteries. The content was originally published in the International Journal of Process Systems Engineering under the title “Economic and environmental analysis of a green energy hub with energy storage under fixed and variable pricing structures” in 2015.

In Chapters 3 and 4 an alternative energy storage type is utilized. Hydrogen for Power-to-gas systems are examined to determine the pricing they would need to achieve in order to be integrated into the grid. Chapter 3 focuses on the pricing of electricity (input) and hydrogen (output) utilizing existing pricing options. The content was originally published in the International Journal of Environmental Studies under the title “Market mechanisms in power-to-gas systems” in 2016. Chapter 4 shifts focus to incentives, specifically examining incentives in the transportation sector for ethanol. In both Chapters policy on why these pricing mechanisms are required and why the government should implement them are discussed.

In Chapter 5 the results of the papers are discussed along with their conclusions. The policy implications are focused on as they are the important results from this thesis. The policy is for Power-to-gas in particular remains as one of the final barriers to implementation and the widespread use of energy storage and clean technology.

1.3 Background

1.3.1 Energy Hubs

An energy hub can be defined by a group of connected infrastructure in which energy can be converted, conditioned, or stored in order to optimize efficiency [6]. These systems manage energy by integrating all forms of energy generation and adjusting, storing, or modifying the energy to be used as an output including the management of electricity and heat [7]. Physically, a hub consists of units that convert and regulate the flow of energy, as well as storage units such as tanks and/or batteries [8]. The hubs are bi-directionally connected to the power grid and can both purchase and sell electricity to the grid in any given hour by utilizing smart grid control methods to efficiently control the flow of energy. Mathematically, they can be modeled through a series of equations and be controlled through various optimization and control loops. Practically, energy hubs can be used to better manage the building load and to allow it to better mirror the energy profile given by wind and solar sources.

An energy hub can control the energy generated from local sources, ranging the combustion of gas to woodchips [9]. Installing new energy generation technologies can, however, be extremely costly. A system that focuses on pre-existing energy sources already in use by the building is a cost-effective component that can be added to an existing commercial building by forming an intermediary stage between the building and the grid [10].

It has been shown that electric vehicle (EV) batteries are able to provide an effective energy storage component to energy hubs, provided that firstly, the discrepancy between energy supply and demand is significant and secondly, a curve control market is used [11]. Previous simulations consider theoretical cost savings and load profiles but did not focus on the energy transfer associated with storage.

In this thesis, a green energy hub (GEH) which utilizes solar and wind energy as well as energy storage from repurposed lithium ion batteries (LIBs) will be explored.

1.3.2 Energy Storage

Due to a lack of energy storage on the Ontario electricity grid, all electricity must be instantaneously consumed or exported to neighbouring jurisdictions. This is an issue as renewable energy does not produce electricity based on demand but rather based on energy availability. As a result of this disjunction between supply and demand, there are times, mostly at night, when the supply can not be further lowered causing energy exporting needs to increase. This need for electricity consumption at times is so great and it exceeds Ontario's demand by a significant degree it can cause the Hourly Ontario Energy Price (HOEP) to become negative [5]. Such pricing necessitates that Ontario pay to export the energy, in addition to the initial cost of its generation.

The seasonal and daily variation in the energy demand of a commercial building often does not coincide with the variation and intermittency of renewable energy availability [10]. For example, a wind turbine generator profile displays peak generation in the mornings and evenings. This contrasts with that of a building's consumption, which has a year round peak during the day [12] [13]. The discrepancy between instantaneous energy demand and generation causes electricity to be bought and sold at various market values throughout the day.

1.3.2.1 Battery Storage

It is estimated that a Lithium Ion Batter (LIB) from an EV could provide a total of 20 years of service [14]. This implies that after 10 years of service in a vehicle, an additional 10 years would remain to provide a means of storing energy in a stationary application. Furthermore, once removed from an EV, these batteries retain approximately 80% of their original capacity, referred to as an 80% state of health (SOH) [15] [16]. It is also reasonable to expect one way charging and discharging efficiencies to each be 80% [11]. This means that, with respect to the available capacity, charging will require 20% more energy and discharging will be able to deliver 80% of the stored energy. The round trip efficiency for energy transfer to and from the battery would thus be 64%. Lastly, the battery pack could be cycled to a maximum depth of discharge (DOD) of 80% to avoid deterioration during secondary use [15].

Considering these figures for the SOH, DOD, and other efficiencies 51.2% (SOH x DOD x Discharge Efficiency) of the original capacity is capable of being delivered from the battery to supply the loads. This means that a LIB with an original capacity of 24kWh would require 19.2kWh to reach a maximum storage level of 15.4kWh, which would be able to supply 12.3kWh to the energy hub when required.

1.3.2.2 Power-to-gas Systems

In many developed nations, there is a push to increase the use of renewable power generation. In Ontario specifically, this need is coupled with the operational demand of managing surplus base load power that is generated by the province's large nuclear capacity. Power-to-gas offers a system-wide energy storage system, which can store excess surplus power and provided needed energy storage to provide consistent output from renewable power sources. Power-to-gas is implemented with electrolyzers, which generate hydrogen with surplus or renewable power. This provides grid stabilization, seasonal storage of bulk power, geographic transmission of energy and dispatchable regeneration of distributed renewable energy [17]. A key advantage of Power-to-gas is the ability to move energy between the electrical and natural gas systems. The conversion of renewable and surplus power to hydrogen through Power-to-gas optimizes the natural gas and electricity networks and limits energy waste and exports. In addition to these benefits, the use of Power-to-gas provides increases the capacity and efficiency of the electrical system without as large a capital cost. A Power-to-gas system can also move energy, in the form of a mixed gas, from one location to another, where the gas can be used to generated electricity or heat, more effectively. In this example and many others, the natural gas infrastructure can offer the electricity system a large, distributed, energy network that can transport energy from one area of the province, or nation, to another while shifting the time between generation and end-use from hours to days or months. In Figure 1 below the Power-to-gas, system includes multiple sections: energy supply, energy conversion, the transmission and storage systems, distribution, conversion and final use.

When examining the production, or well-to-pump energy consumption and emissions, of hydrogen it was shown that, there is a great dependence on both the method of creating hydrogen and the method of generating electricity when electrolysis is used [18]. This shows that using renewable energy helps significantly reduce emissions and energy consumption, especially over hydrogen created through Steam Methane Reformation. Pervious work has shown that hydrogen can be used as a mechanism for energy storage and have been compared to other storage means [19]. In the Power-to-gas mechanism, hydrogen is created from a surplus of energy from often over 20% renewable sources when the generation is greater of electricity by the grid is greater than the demand [20]. The energy used to power electrolyzers from grid electricity can be used as a method of matching consumption and demand through the provision of ancillary services [19], [20]. Once the hydrogen is produced, it can travel along various pathways. The hydrogen can be directly passed on as a product for industrial applications or transportation (hydrogen fuel cells). Should the hydrogen not immediately be required the hydrogen can be compressed and stored for later use, completing something commonly called load shifting [19], [20], [21]. Alternatively, the hydrogen can safely enter the natural gas network, maintaining a maximum volume concentration of 5% [22]

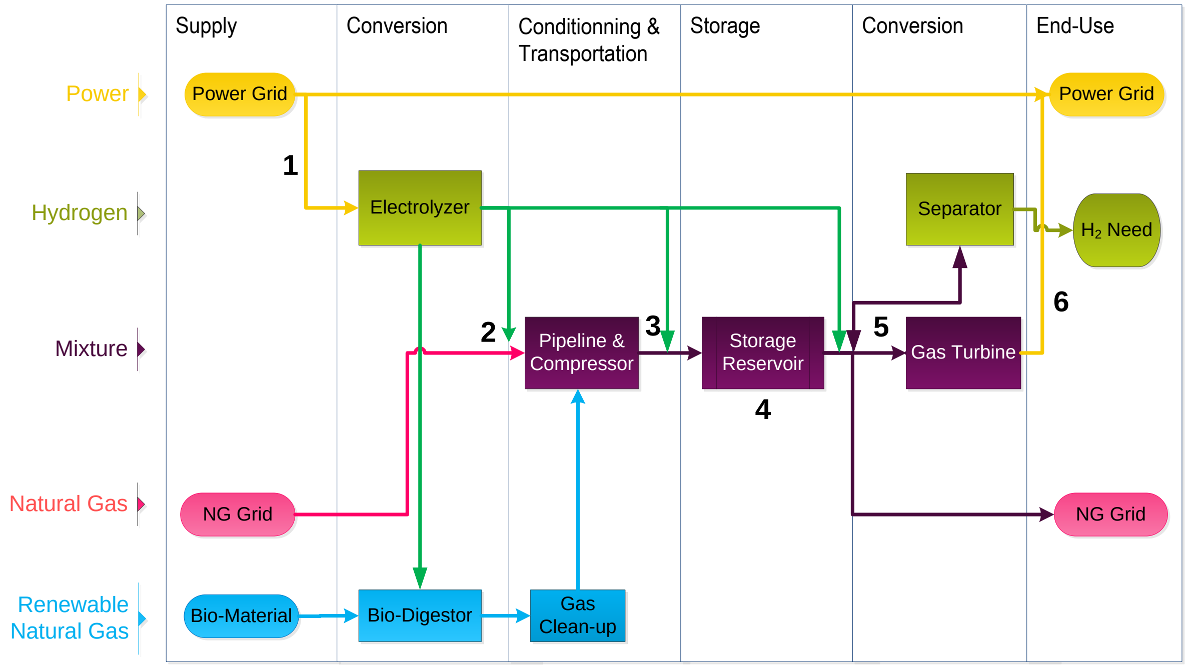

Figure 2: Basic Concept Illustration for Power-to-Gas, Adapted from [23]

The hydrogen produced using surplus off-peak power can be directed to hydrogen customers, stored on-site or injected into the natural gas pipelines to create Hydrogen Enriched Natural Gas (HENG). HENG can is then sold to natural gas customers, used to produce electricity with a Combined Cycle Gas Turbine, or fed to a separator to reconstitute a pure hydrogen stream for industrial or transportation use. In places where seasonal energy demand varies due, such as Canada, seasonal energy storage and efficient energy distribution is required.

Power-to-gas, in addition to providing services and flexibility to the energy grids also produces an important fuel, hydrogen. Hydrogen is used in the hydrocarbon industry for semiconductors, coolants, as an additive in gasoline and could be used in the hydrogen economy as fuel cell vehicles are being released by major vehicle companies in the coming years [24]. This potentially low cost alternative eliminates the need for Steam Methane Reforming (SMR), which runs on carbon-rich fuels and produces CO_2. The emissions for production are zero and only emissions from the production of electricity would be considered. If the production of electricity for a jurisdiction is largely nuclear, wind, and solar, which accounts for approximately 60% in Ontario, Canada, then the emissions are reduced even further.

1.3.2.3 Existing Power-to-gas Projects

There are a number of Power-to-gas demonstration projects globally, with some producing hydrogen to be stored in tanks onsite and others using the natural gas infrastructure to distribute and store the gas [25]. An example of a Power-to-gas plant using the natural gas pipelines is a 2MW storage facility in Falkenhagen, Germany, which was developed by E-ON in partnership with Hydrogenics and began operation in 2013 [26]. The plant uses surplus energy from renewable energy sources to produce hydrogen and injects it into a natural gas (NG) pipeline network. Under full operation, the facility feeds approximately 360 Nm^3 per hour of hydrogen into the NG pipeline system. With the transition of the German power generation system to an increasing amount of renewable power, there are over 30 other demonstration projects in various stages of implementation [27]. In Ontario a 2 MW demonstration project for Power-to-gas is also under development [28].

1.3.3 Industrial and Commercial Sector Energy

According to Statistics Canada's most recent Energy Statistics Handbook, the commercial and institutional sectors consumed 11.1%, or 1.3×10^9 Wh, of the total energy produced in Canada in 2009 [29]. Solar and wind energy have been utilized by these sectors to offset some of their high-energy demands. Wind power alone has increased in Ontario from 0.9% to 3.4% from 2008 to 2013 [9]. The increase in power output from renewable sources has helped to decrease the dependence on coal from 14.5% to 2.1% within the same time period [9]. The provincial goal of eliminating coal power by December 31, 2014 will be supported by the 1.3x106W of commercial wind power commissioned by the Ontario provincial government in this year [9] [30].

1.3.4 Transportation Sector Energy and Emissions

The transportation energy used by consumers has increased, on average, by 1.9% in Canada from 1990-2011, with a change of -1.5%, 4.1%, and 1.6% for 2009, 2010, and 2011 respectively [31] [32]. The increase comes despite the energy reductions achieved by car manufacturers whom have been able to achieve a decline in both energy use and energy intensity of 13.4% and 20.7% to 1.82 MJ per passenger-km. There are two causes of energy increase: an increase in consumers' km driven and the increased use of freight vehicles due to online ordering. The energy intensity of freight has risen dramatically over the 20-year period. The increase from medium, heavy and light freight vehicles ranges from 19.4% to 168.7%, helping the freight intensity to increase by 14.9% to 1.36 MJ per km. With these large energy increases, academia, industry, and governments are attempting to curb energy consumption during the use phase vehicle as well as reducing the well-to-pump emissions related to vehicle fuel. Government programs like the Corporate Average Fuel Economy (CAFÉ) standards in the United States, which target light to heavy-duty vehicles, are also being used in Canada. These energy-efficiency reduction strategies will help decrease the secondary energy use in transportation, meaning the energy consumed onboard the vehicle.

Governments are also working to reduce both primary energy and emissions associated with transportation fuel. To this end, different energy sources are being examined for the use in transportation systems, such as biofuels, hydrogen, and electricity. These fuels vary in their implementation, efficiency and emissions. Biofuels, for example, can largely be relatively easily with only minor modifications of an internal combustion engine and fuel systems. Although biofuels operate with a minimal energy reduction, they can reduce well-to-wheel emissions. Electricity and hydrogen however vary with how they are generated and require the powertrain of a vehicle to be modified to either partially or wholly run off this energy source.

1.3.4.1 Alternative engine fueling

By making engine modifications an engine can be made to run on a gas, an alternative liquid fuel, a blend of traditional and alternative liquid fuel, or a combination of gas and liquid fuels. This work focuses on blended fuels and dual fuels, specifically ethanol and biodiesel blended fuels and hydrogen diesel blended fuels.

1.3.4.1.1 Ethanol

Ethanol has been heavily researched and has multiple benefits in its production and vehicle implementation. Ethanol is derived from a variety of sources and can be categorized into sugar-based and cellulose-based ethanol. Sugar-based ethanol is produced from sugar cane or corn whereas cellulose ethanol comes from plants like switch grass. In addition to the different sources, there is also a stark difference in the energy and emissions of ethanol production from starch and cellulose [18]. For an 85% ethanol blend, starch-derived ethanol varies in energy input between 1.5 and 1.8 J of input per J of fuel while cellulose derived ethanol varies between 1.9 and 2.5 J of input per J of fuel [18]. For the same blends, the well-to-wheel emissions of cellulose ethanol are more favorable ranging between 10 and 30 g $CO_{2\,eq}$ per MJ of fuel while starch based ethanol ranges from 15 to 85 g CO_2e per MJ of fuel. Ethanol is combined with gasoline in various ratios, and combusted in an internal combustion engine with minor engine modifications. Ethanol has been shown to reduce both hydrocarbon and nitrous oxide emissions [33]. Carbon dioxide emissions are reduced by 1.4% to 5% during typical vehicle operation and it has therefore been noted that the real potential for emissions reduction comes from the production or well-to-pump emissions associated with ethanol [34]. It is important to note however that slight increases in urban emissions was also seen [34].

1.3.4.1.2 Biodiesel

Biodiesel is an alternative biofuel that can be combined with regular diesel in an effort to displace traditional petroleum products. Biodiesel is created by combining oils such as soybean oil, with regular diesel in a ratio of up to 20% (B20). The energy requirements for biodiesel are less than that of ethanol-based fuels however have lower differences between blend percentages. The energy required for the creation of biodiesel ranges from 1.2J to 1.3J of input per J of fuel for 0% to 20% biofuels, respectively [18]. The carbon emissions are reduced however with the addition of biodiesel and are reduced by up to 8g CO_2e per MJ of fuel [18]. Vehicle energy and emissions of biodiesel do show positive results for criteria emissions. Using B20, particulate matter emissions are reduced by approximately 12%, while hydrocarbon emissions are reduced by 20% [35]. Nitrous oxide emissions are however known to increase with biodiesel [35]. There are marginal changes to the engine efficiency with biodiesel, showing again how the benefits of biodiesel are largely in the production of the fuel and not the onboard operation [36].

1.3.4.1.3 Hydrogen

Hydrogen is typically used to power fuel-cell designed vehicles; however, hydrogen is also used to fuel an engine in combination with diesel in a duel fuel system, where hydrogen is added to the air before the cylinder, to aid in combustion. Hydrogen can be created through a number of technologies including thermoelectric composition, electrolysis or steam methane reformation. When examining the well-to-pump energy requirements, which includes energy in the finished fuel, the well-to-wheel energy varies from 1.6J to 2.9J of input per J of fuel [18]. This large range covers electrolytic, gasified, and reformed hydrogen; however, the examination of different types of hydrogen production is not the cause of the large range of energy inputs. When looking at just gaseous hydrogen, both the smallest and the largest energy requirements are from electrolysis process. This is because using non-renewable fuels uses much more energy than renewable energy sources. Using renewable fuels in electrolysis produces the best energy results while biomass produces the best emission results, yielding wheel to tank emissions of 10g of CO_2e per MJ of fuel.

When hydrogen is injected into a diesel engine, there are multiple benefits as it is a carbon-free fuel. The addition of hydrogen has been shown to reduce soot, a significant emission of diesel engines, by up to 40% [37]. Due to the higher burning temperature of hydrogen, however, nitrous oxide emissions tend to increase [38] with hydrogen dual-fuels [37]. There is, in addition to the lack of CO_2 emissions, an efficiency increase of up to 37% when compared to a conventional diesel engine [39].

1.3.5 Carbon Accounting

Greenhouse gas (GHG) emissions from power generation form the third largest emitting sector in Canada at 86Mt in 2012 [29]. GHG emission reporting has historically been associated with the energy producer [40]. However, companies who are looking for emission reductions are now looking at GHG emissions holistically and including emissions from consumption from sources such as electricity [41]. This holistic approach gives companies more opportunities to reduce their carbon footprint.

Electricity consumption can be a major source of emission reduction for companies that do not directly emit GHGs [41]. The emission governing body however cannot count consumption-based emissions to avoid double counting [41]. This makes policy more difficult as emission reduction is targeted at one front and not both [40]. A three-scope system has been proposed as a standard to be able to account for all emissions while not double counting [41].

Emissions that are directly produced by a company would be accounted for under Scope 1 emissions [41]. These emissions can be directly controlled and reduced by means of more efficient or less producing systems. This could be from an electricity generating company changing its electricity mix to cleaner sources. Emissions that are indirectly emitted based on the consumption of electricity would be accounted for under Scope 2 emissions [41]. These emissions can only be minimized through a reduction in the electricity consumed. Scope 3 emissions are all other indirect emissions [41].

With the scope of all emissions outlined, the scope 1 and 2 emissions can be calculated from the production and consumption of electricity based on source. These calculations could be important for government programs for carbon accounting, such as Cap and Trade or Carbon Tax.

1.3.6 Government Policy and Programs

1.3.6.1 Feed-in-Tariff Program

Wind and solar power have also been increased through programs in Ontario such as the Feed-in Tariff (FIT) program. The FIT program is a project that may bring 11x106W of non-hydro renewable power to the province [42]. The program operates by utilizing localized energy hubs which are macroscopic systems that integrate all energy forms (electrical, gas, heating) into a single system and provides management control for the efficient production and consumption of energy within the scope [7]. The projects in question have a power capacity greater than 10x106W and are offered a fixed price for the electricity they provide [43]. The contracted pricing is, however, typically above the market price of electricity. In fact, a government report has deemed the price to be too high and had called for a reduction of up to 20% in 2012 [42]. The FIT price for solar electricity has, as of January 2014, been reduced by approximately 50% from its original selling price [43].

1.3.6.2 Government Incentives

Governments are attempting to gain energy independence through the examination of alternative fuels. This push is largely seen through government programs, which offer incentives for the creation of biofuels. Under the Clean Air Act, the United States Environmental Protection Agency (EPA) developed a preliminary Renewable Fuel Standard (RFS) in 2005 under which the rules for the mandatory blending of biofuels with gasoline are set [44]. The advantages of blending renewable ethanol with gasoline are that there is a resultant lowering of emissions and that vehicles in the North American are produced to handle ethanol concentrations of up to 10% in their fuel. In the United States, about half of the available gasoline available contains renewable ethanol. However, there are troubles distributing ethanol due to the tendency of ethanol to cause corrosion in pipelines and the need to send ethanol from Midwestern America outward – the opposite direction that oil is transported. In order to meet the standards set by the EPA, the various renewable fuels must generate significant savings over the gasoline and diesel that they replace. Conventional biofuels, such as corn or sorghum-based ethanols are intended to provide a 20% life cycle reduction in emissions. [45]

In the United States of America (USA), the promotion of renewable biofuels has been undertaken by the use of the RFS. The RFS, which passed in 2007, is used by the United States' Environmental Protection Agency (EPA) to set out how much of each type of ethanol must be blended with each barrel of gasoline and how much biomass diesel will be needed. Using these values, the EPA can set out achievable greenhouse gas emission reductions.

The production of the various biofuels is supported with tax credits on a per gallon basis. For example, the Cellulosic Biofuels Production Tax Credit, which expired at the end of 2012, was meant for all types of energy producers and is worth a value of $1.01 per U.S. gallon of eligible biofuel produced. The value of these tax credits is expected to reach over $20 billion dollars by 2020 [46]. The success of these standards in reducing overall emissions is debatable. Bento et al. [47] suggests that the performance of the RFS in reducing emissions is strongly tied to the ability of the policy regime to account for carbon leakage. Of specific issue for the generation of renewable biofuels is whether the emissions associated with developing the land to harvest these crops for fuel, as well as those for food, causes a net-increase in greenhouse gas emissions. One approach to this problem is to utilize a multi-sectoral approach for overall greenhouse gas emissions reductions.

1.3.6.3 Cap and Trade

Cap and trade is another government program that can be used to reduce emissions [48]. It does this by setting a limit to the emissions that an individual company can produce [49]. If the company can reduce its emissions that it can receive credits for the reduction. These reductions can then be sold to companies who are unable to meet the target. This produces a financial incentive for both parties to reduce emission and the system has been implemented in multiple jurisdictions within North America [50].

Cap and trade is an important reason to consider energy storage as the emission reduction potential of the system is high, as demonstrated in Chapter 4. Energy storage can allow the for the expansion of renewable zero emission energy sources. In the case of Power-to-gas systems, clean electrolytic hydrogen can be created from renewable energy to displace steam methane reformation. Power-to-gas also has greater emission reduction potential than ethanol for the transportation sector as demonstrated in Chapter 4, furthering the credits that could be obtained to offset the capital cost.

Though cap and trade is not explicitly examined in this work, the emission reductions for these systems is analyzed. Therefore, policy inferences for this or other government programs are made in the conclusions to show the viability of energy storage systems.

Chapter 2: BATTERY ENERGY STORAGE

The following chapter details the initial works during my thesis which culminated into a paper published in the International Journal of Process Systems Engineering under the title "Economic and environmental analysis of a green energy hub with energy storage under fixed and variable pricing structures" in 2015. The work was written by me with the support of the other authors including Jennifer Cocking who co-wrote the initial report; Dr. Sean B Walker who aided with the introduction; Dr. Michael Fowler, Dr. Roydon Fraser, and Dr. Steven B Young who aided in editing the work; and Leila Ahmadi, Alan Thai, Jake Yeung, and Arthur Yip who provided foundational code and background material. All authors have given approval for use in this thesis as the concepts and ideas are solely my own.

The following chapter describes an energy hub with power generation, consumption, and storage in the form or repurposed electric vehicle lithium ion batteries. The energy hub is created at a Walmart Inc. distribution center with solar and wind power. The facility has cooling and lighting as the main energy sinks, however electrolyzes also are sinks which generate hydrogen to fuel the fleet of fuel cell fork lifts. The modeling of the facility examines the financial mechanisms to make energy storage viable and contrasts the Feed-in-Tariff to market pricing.

2.1 Methodology

2.1.1 Energy Hub Design

There are many components to the design of a GEH. The system includes energy generating systems, load management systems, building loads, and energy storage systems. All of these systems work together to create a more efficient system that increases the benefits of renewable energy.

2.1.1.1 Energy Generating Systems

The energy generating systems include solar panels and wind turbines that are capable of meeting part of the building load requirement. The remaining energy requirements are fulfilled by the Ontario power grid. To perform the optimization, two different generation capacities for both wind and solar are used creating 4 possible GEH designs. 4 or 5 wind turbines with a capacity of 1.5×10^6W each were examined. Each wind turbine uses a scaled version of the power curve shown in Figure 3 to determine the power output according at a given time of day. The wind speed is determined by examining the wind speed profile, shown in Figure 4, for a nearby city from the National Climate Data and Information Archive [51]. The wind speed profile, in combination with the power output curve are thus used to determine the wind energy generated for any given hour and was fed directly into the GEH.

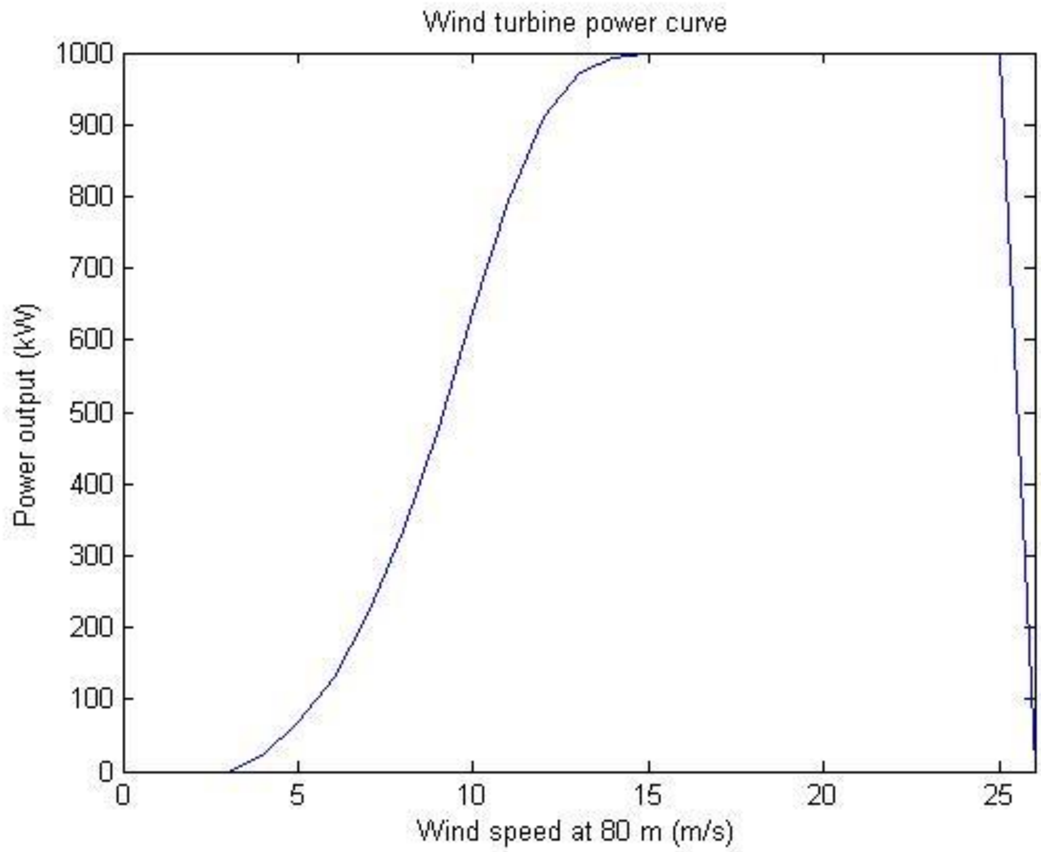

Figure 3: Power curve for a 1.0x106W wind turbine at 80m

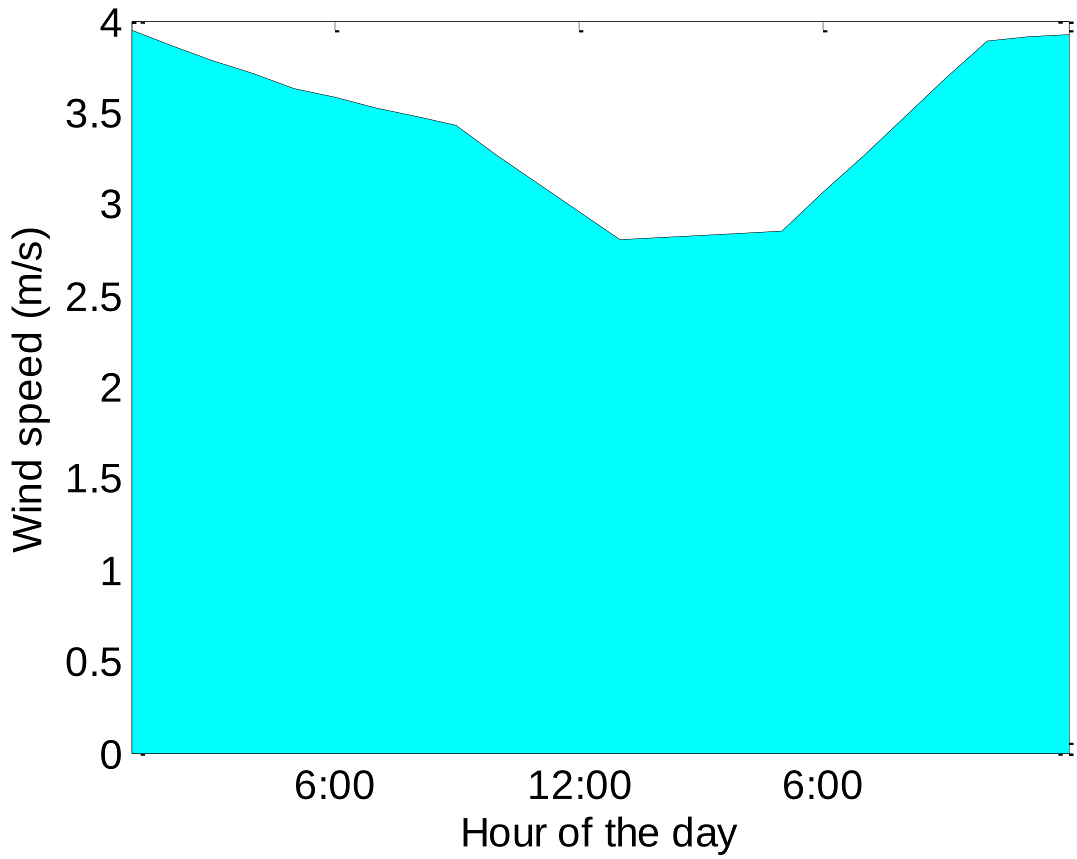

Figure 4: Wind profile for an average winter's day

Solar panels, with a total capacity 3.0×10^6W or 4.0×10^6W and which would cover a maximum of two thirds of the surface area of the Wal-Mart Stores Inc.'s distribution centre are used as a basis for the analysis. Solar irradiance data is also collected from the National Climate Data and Information Archive. An assumption of 10% efficiency in the solar power generation is made to account for the solar array efficiencies, panel angles, and other efficiency losses due to factors such as dirt, snow, or ice accumulated on the panel's surface. An adjustment to the solar profile, shown in Figure 5, is made to account for the change in day length in the winter. Four hours of solar irradiation are eliminated making the solar profile narrower for the winter season.

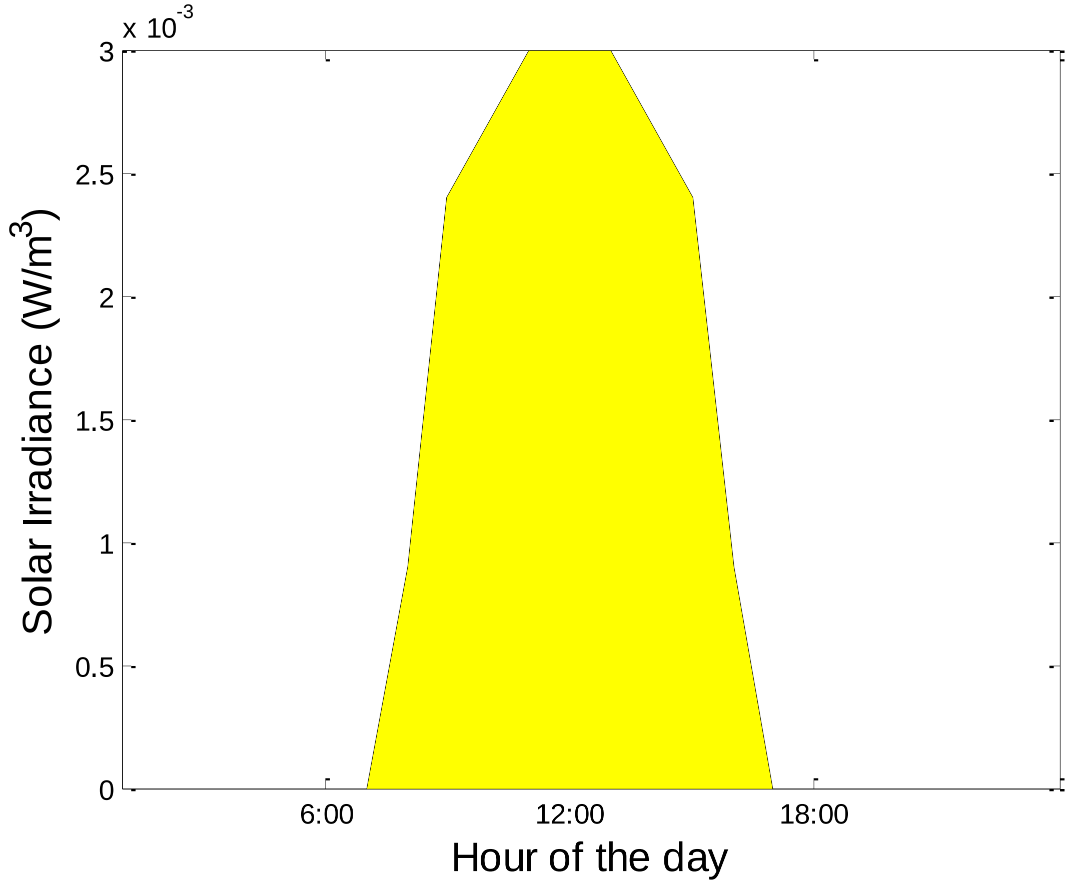

Figure 5: Solar irradiance profile for an average summer day

There are, therefore, 4 different GEH designs that are considered. The selection of the GEH design is based on the optimization of the net renewable energy (NRE), which compares the total amount of power created by the renewable power generation sources with the total building and forklift load. The net renewable energy does not include consideration of when the energy is being produced and consumed meaning not all energy produced is actually used within the GEH. For this reason the Grid Reliance (GR) is also examined which compares the amount of power drawn from the provincial grid with the total building load. Wal-Mart Stores Inc. wished to achieve a 100% net renewable, which is therefore the goal of the GEH.

$$NRE = \frac{Total\ Renewable\ Power\ Generation}{Total\ Load\ Requirement} \qquad 2.1$$

$$GR = \frac{Total\ Grid\ Requirement}{Total\ Load\ Requirement} \qquad 2.2$$

2.1.1.2 Load Management Systems

Load management systems are able to control the buildings loads to decrease its peak power draw. This is done in two main methods: the adjustment of refrigeration temperature, and the adjustment of lighting. By allowing for some temperature fluctuation, the refrigeration load can be adjusted as to reduce peak power consumption when local energy is insufficient. Increasing the refrigeration load when power is available within the GEH then allows load shifting to occur. Utilizing dimmable LED lighting the lighting load can be decreased if power from the GEH is insufficient, further reducing the peak load requirements.

Further load management is conducted through the transformation of electrical energy into hydrogen energy. This is done through electrolysers, which can be integrated either outside or inside the facility and were part of the GEH created. The HySTAT-60 is considered and has a capacity to convert 3.12×10^5W of power into hydrogen. The hydrogen generated is not converted back into electricity and therefore should not be considered an energy storage medium in this GEH design but rather a highly variable load. The production of hydrogen is a mechanism to capitalize on the excess electricity created within the GEH and is an energy vector solely which supplies fuel to the fuel cell powered forklifts used at the distribution centre. The power consumed for hydrogen generation is therefore equal to the forklift load.

2.1.2 System Load Requirements

The building load is taken from a Wal-Mart Stores Inc. distribution centre in another location and scaled to the ca. 74,000m^2 facility examined. The load profile is also adjusted to take into consideration the cooler climate at the facility in question which reduces the refrigeration requirements. There are three specific building loads considered: refrigeration units, lighting systems, and forklifts. The first two are included in the load profile created in Figure 6. These loads are adjustable and are controlled using the load management systems.

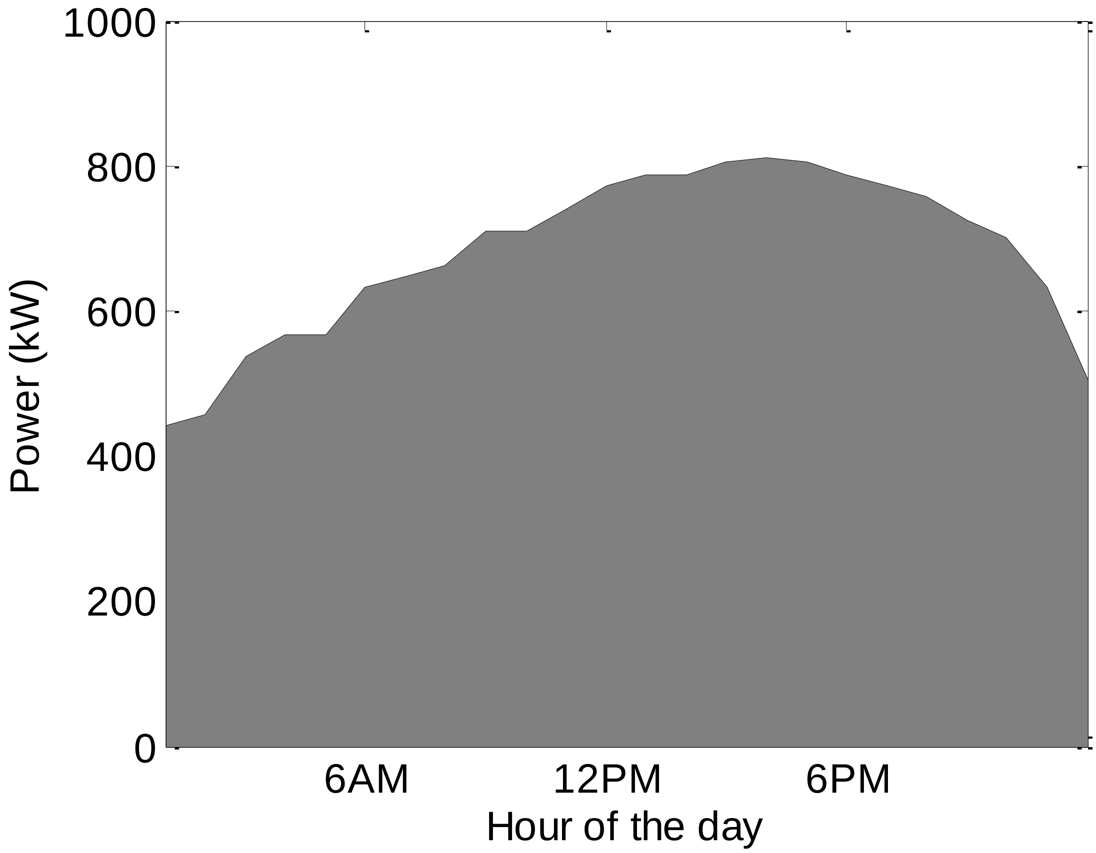

Figure 6: Load profile for a food distribution centre for an average winter day

The forklift load allows the most load management as hydrogen storage vessels allow for hydrogen the storage of hydrogen fuel. The storage of hydrogen allows for load shifting to occur and forklifts to refuel as required. The model considered 140 forklifts to run the distribution centre, with a fuel requirement of X kg H2/day/forklift. This assumption is made using data from forklift consumption run at Balzac, as described in confidential data from Wal-Mart Stores Inc. [52]. The total load requirement for the forklifts is determined using Equation 3. This forklift load requirement is in addition to the load requirements shown in the load profile. This load is added to the appropriate time of the day to increase the system efficiency and is controlled by the load management system through the electrolyser.

$$Load_{Forklift} = \frac{(\#\ forklifts)(H_2\ consumption)(H_2\ molar\ volume)(energy\ density)}{(H_2\ consumption)} \qquad 2.3$$

The remaining building loads are already considered in the load profile and will not be adjustable for the purposes of this model.

2.1.3 Energy Storage Systems

Energy storage is an additional layer in the GEH and is examined after the initial GEH is completed. Energy storage is incorporated in the form of re purposed batteries from EVs. The batteries are integrated into the system and are available for charge and discharge at any given moment in the simulation. This allows the GEH to store energy when there is a local surplus and provide additional energy when there is a local deficit, decreasing the grid reliance.

To determine the viability of adding energy storage, multiple simulations were run utilizing different number of packs. The simulation was run with a 24kWh new pack capacity, which is the capacity of a pure electric vehicle (Nissan Canada, 2014).

The addition of energy storage completes the GEH. A completed diagram with the energy flow is shown in Figure 7.

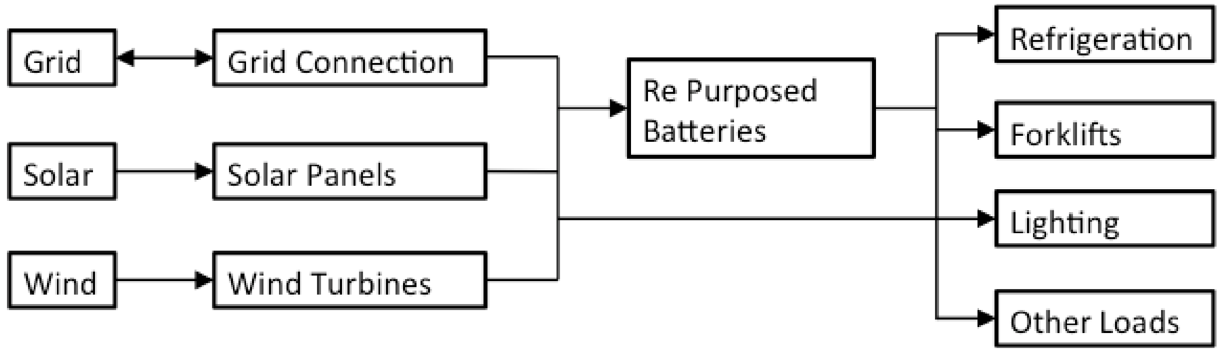

Figure 7: GEH design with energy vector paths

2.2 Simulation

The simulation is completed in two stages. Both simulations are completed using MATLAB software. The first stage determined how renewables are to be integrated into the GEH and addressed the load management systems in order to increase GEH's efficiency. Once the renewable generation capacity required to achieve 100% NRE is determined the second stage is completed. The second stage entailed modeling the energy storage potential from the addition of re purposed batteries into the GEH.

2.2.1 Simulation: Stage 1

There are 5 components involved in the Stage 1 model shown in Figure 8. Initialization is completed to collect all the data from the external sources that are required for the simulation. The simulate component determines the load requirements for the building and the power generated from the sources. An energy balance is then run to determine what load could be added for the generation of hydrogen. Load adjustment is then completed using the load management systems to increase the GEH's efficiency. The final results from the simulation are then examined to allow for further analysis and a calculation of the NRE and GR.

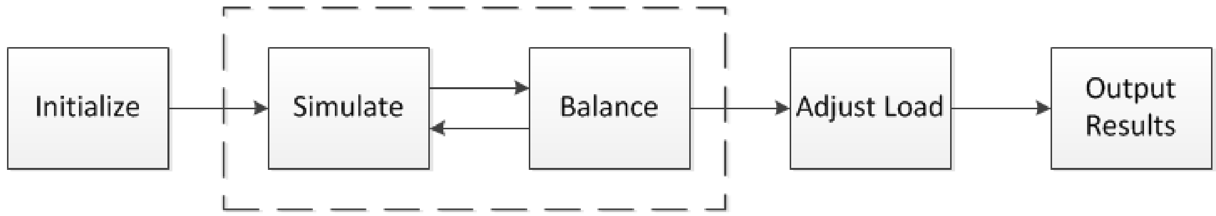

Figure 8: Components of the stage one simulation

The simulation only considered factors within the GEH and the only external inputs are the solar irradiance and wind speeds. No calculations considers data pertaining to the grid connection or electricity price. No consideration of energy storage is completed at this time.

2.2.2 Simulation: Stage 2

Energy storage modeling is completed through a second simulation that utilized the output data from the stage one simulation. The Stage 2 simulation does not only utilize data from within the GEH but also data from external sources. In addition to the energy generation, load requirement, and load shifting data, the Hourly Ontario Electricity Price (HOEP), and the battery's capacity is considered. The HOEP is obtained from the Independent Electricity System Operator (IESO) [5].

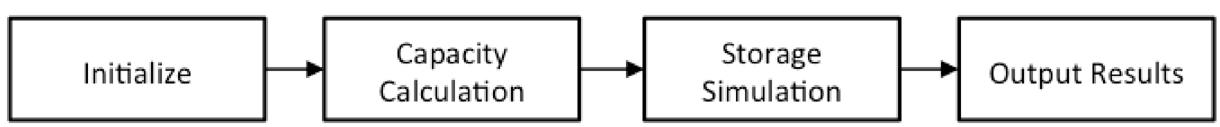

Figure 9: Components of stage two simulation

The process for the Stage 2 simulation is similar to the Stage 1 simulation. Initialization is completed in order to collect the data from the previous stage as well as the HEOP and basic battery parameters such as new capacity, DOD, SOH, and charge efficiency. The battery parameters are then used to calculate the usable per pack capacity of the battery packs.

$$\textit{Usable Per Pack Capacity} = (\textit{New Capacity})(\textit{SOH})(\textit{DOD}) \qquad 2.4$$

The storage simulation is then run for multiple numbers of packs. The storage simulation looks at three main parameters when deciding whether to charge, discharge, or do nothing. The parameters are: the HOEP, the net energy within the GEH, and the state of charge (SOC). From these three parameters there are 5 scenarios that determine interaction of the batteries within the GEH.

Table 1: Stage two simulation scenarios

Case	Model Input	Model Reaction
1	Storage available HOEP is positive GEH has a surplus	As long as the HOEP is below the transport fee, charge from renewables within GEH. Otherwise do nothing
2	Storage available HOEP is negative GEH has a surplus	Charge from renewables within GEH.
3	Storage available HOEP is negative GEH has a deficit	As long as the transport fee is greater than the absolute HOEP, charge from the grid. Profit from charging calculated.
4	Energy available HOEP is negative GEH has a deficit	As long as the HOEP is greater than the daily average HOEP, discharge from battery. Savings from reduced grid reliance calculated.
5	All other combinations	No action taken.

Upon completion of the simulation the data is exported to excel. Within excel further post processing is completed to determine the economic viability of the GEH. The NRE remains unchanged after the Stage 2 simulation as no new end load or source was added to the system. The energy was stored in the battery is later used and though it is treated like either a source or a load during the simulation, on a longer time scale it acts as neither. The battery however does impact the GR as the battery acts as energy storage and aids with load management, reducing the amount of electricity required from the grid when a GEH energy deficit was seen.

2.2.3 Financial Post Processing

To determine the economic viability of using repurposed EV LBP for energy storage to generate savings from the implementation of energy storage into the GEH, the simple payback period (SPP) and internal rate of return (IRR) are calculated. The values are calculated using the capital cost of the battery, which includes the physical pack, insulation, and interface equipment, and the net yearly savings. There is also an operating and maintenance charge based on the amount of electricity discharged from the battery. The net yearly savings are calculated based on the savings generated from using the pack minus the operation and maintenance cost of the pack.

Table 2: Pack cost parameters [15]

Project Expenses	Amount
Pack Capital Cost (per unit)	$2,712
Pack Interface Cost (fixed)	$389
Installation (fixed)	$110
O&M (per MW-year)	$74

In addition to the HOEP, the delivery rates and Global Adjustment (GA) are considered when calculating the buildings electricity cost. The delivery rates are recorded form Hydro One, an Ontario electricity distributer. The delivery charges are used as part of simulation to minimize the amount of paid in delivery charges by exporting electricity from the GEH. The GA is not considered as part of the logic but is rather a fee calculated based on the amount of electricity purchased form the grid within each month.

Table 3: Delivery rate charges per MWh [54]

Delivery Charge	Amount ($/MWh)
Debt Retirement Charge	7
Distribution Volume Charge	41.4
Transmission Charge (Connection)	3.5
Transmission Charge (Network)	5.27
Total	57.17

To calculate the revenue from the sale of electricity two models were explored. The sale of electricity was completed using the HOEP with no other fees and with the rates outlined in the FIT program. Due to the different rate for solar and wind of a weighted average based on capacity was used which was $0.18/kWh.

The calculation of the IRR for multiple pack capacities allowed two main parameters to be determined. The economic threshold for a profitable project, where the IRR is equal to the discount rate, was 5% in this calculation. This economic threshold could be used along with regression to determine the dollar per kWh cost that must be seen for this system to be profitable. Utilizing the dollar per kWh cost and applying it to the results for each battery pack, further regression analysis helped to determine the approximate minimum yearly savings required to achieve profitability.

2.3 Results

2.3.1 Net Renewable Energy

As described previously, net grid reliance allows one to determine the GEH generation in comparison to its consumption. The Stage 1 simulation was completed in for the different cases shown in Table 4 to optimize to 100% NRE. This is due to Wal-Mart Stores Inc.'s goal to achieve 100% renewability, regardless of whether it was used locally or not. To achieve this, 4.0MW of solar and 9.0MW of wind power generation must be used.

Table 4: Net renewable energy for various solar and wind capacities

Capacity (MW)		Net Renewable Energy (%)
Solar	Wind	
3.0	9.0	87
3.0	10.5	95
4.0	9.0	100
4.0	10.5	108

When 4.0 MW of solar and 10.5 MW of wind are used in the GEH the total generation of electricity exceeds the total yearly demand. This leads to a NRE of 108% which is greater than the goal. This case would have higher capital cost and risk that is not required or needed in the system. Due to this only 4.0 MW of solar and 9.0 MW of wind are further examined.

2.3.2 Net Grid Reliance

The GR is not only a function of the GEH design but also of how the renewable energy was sold and purchased. By utilizing more local electricity within the GEH the GR can be reduced creating a more independent system. To explore how the GR changes 6 cases are put through the simulation to show how modifying different parts of the GEH or energy flows within the GEH change.

There are two possible applications of the local solar and wind. The electricity generated could be used first to supply the load within the GEH and are designated as Local Renewable Energy (LRE). This system would make the GEH like a micro grid which would then bring many other benefits to the system [55]. The surplus electricity in a given hour would then be sold to the grid under the FIT or the HOEP program. The addition of batteries forms (designated with B) and shifting the electrolyser load to high renewable energy times (designated with S) forms 3 additional cases.

The second possibility is to treat the power generation and consumption as two independent systems and is designated as Independent Renewable Energy (IRE). This case is the case for the current systems under the FIT program in Ontario, Canada. By treating the two systems independently all of the electricity generated gets sold directly to the grid. The loads are then supplied solely form the grid giving it a GR of 100% as is also the case with the original case.

Table 5: Grid reliance for different GEH configurations and flow structures

Case	GR
Original	100.00%
LRE	27.69%
LRE-B	27.50%
LRE-S	23.55%
LRE-S-B	23.38%
IRE	100.00%

By designing a more independent GEH that could easily be created into a micro grid the GR was decreased to as low as 23.38%. This was achieved in the case where the system was optimized to maximize the internal use of electricity. Not only was the renewable energy used locally first but also energy storage was used and the electrolyser load was shifted to times where a surplus existed.

The addition of energy storage, whether there was electrolyser load shifting or not, did decrease the electrolyser loads. The GR decreased by 0.17% and .19%. Though as a fraction it is small the power reduction is ca. 2500kWh and was achieved by using 4 packs with a total usable capacity of 76.8kWh.

2.3.3 Yearly Electricity Costs

There is a reduction in the yearly electricity cost in all of the 12 cases when compared to the original yearly electricity cost. All GEH configurations were run under both the HOEP and FIT pricing structures and are compared to the original yearly cost of ca. $1,800,000. When the

HOEP pricing is used the yearly electricity cost remains positive and ranges from ca. $320,000 to ca. $1,400,000. The two largest within the HOEP pricing structure come from when the renewable energy is treated as an independent system, while the lowest cost is in the case where local energy is utilized and all load shifting measures are implemented.

Under the FIT structure all yearly electricity costs are negative meaning there is a net income from the selling of electricity to the grid. The net revenue ranges from ca. $160,000 to ca. $710,000 where the renewable generation acts as an independent system. This is the opposite of HOEP structure due to the lucrative selling price set by the FIT program, which is significantly higher than the average HOEP price.

Table 6: Annual electricity cost for all configurations of GEH, pricing structure, and flow structures

Case	Electricity Cost
Original	$1,779,722.88
IRE-HOEP-S	$1,365,550.02
IRE-HOEP	$1,363,099.94
LRE-HOEP	$372,685.61
LRE-HOEP-B	$370,424.41
LRE-HOEP-S	$318,785.78
LRE-HOEP-S-B	$316,744.89
LRE-FIT-S-B	$(159,592.18)
LRE-FIT-S	$(161,026.55)
LRE-FIT-B	$(190,434.81)
LRE-FIT	$(192,158.07)
IRE-FIT-S	$(709,871.78)
IRE-FIT	$(712,321.86)

2.4 Discussion

2.4.1 Green House Gas Emissions

Greenhouse gas emissions of different forms of energy are used to calculate GHG emissions using ISO 14001 life-cycle analysis (LCA) methodology. The LCA methodology allows consideration of greenhouse gas emissions emitted during the entire life cycle of the electricity generated from each source, Table 7 [56].

Table 7: LCA greenhouse gas emissions from power generation sources [56] [57]

Power Source	GHG emissions (g CO2/kWh)
Solar	32
Nuclear	66
Hydro	10
Gas	443
Coal	960
Wind	10.05

Using the supply mix from both the grid and the GEH the emission factor is determined [9]. The LCA emission factor for the grid is determined to be 172g CO_2/kWh and for the GEH is determined to be 21g CO_2/kWh. These factors are then be used, along with the total yearly electricity consumption and the GR to obtain the carbon emissions for each case.

2.4.1.1 Scope 1 Emissions

Due to the addition of energy production systems there are Scope 1 emissions associated with the GEH. Using given LCA emission factors the GEH produces $2.22\text{x}10^8$g of CO_2 from solar and $7.18\text{x}10^7$g of CO_2 from wind power generation. Though these emissions would not otherwise be seen in the GEH, from a province wide power generation perspective the same amount of energy generated from coal, which solar and wind are replacing, would have produced $1.32\text{x}10^{10}$g of CO_2. As a province the addition of solar and wind in localized hubs owned by the consumers would reduce the overall emissions as well as shift some of those emissions from large generation corporations to more distributed consumers.

2.4.1.2 Scope 2 Emissions

GHG emissions related to the power consumption of the building can be considered using Scope 2 emissions. The emissions considered are therefore based solely on the consumption of electricity in relation to its source. For an independent renewable energy system the electricity comes solely form grid so the renewable energy cannot be considered under Scope 2. However in a local renewable energy system the GR can be used to determine from where the electricity is being produced and can calculate the associated emissions.

When the design of the system utilizes local energy first, before exporting excess, there are significant emissions reductions. By using local solar and wind the GEH can claim 100% of the emission reductions from the production of electricity from renewables it consumes. With this benefit the Scope 2 emissions are reduced to ca. 1/3 of the original emissions for all cases. There are associated emissions from both local and grid power sources however the savings come from the difference between the two greenhouse gas emission factors. By using local energy up to $15.98\text{x}10^8$g of CO_2 can be eliminated from the Scope 2 emissions. The reduction is primarily attributed to the use of localized renewables with ca. $8\text{x}10^7$g associated with the shifting of the electrolyser load and ca. $4\text{x}10^7$g associated with the use of energy storage.

Table 8: Scope 2 GHG emissions for all cases and difference from original system

Case	Emissions (g CO_2) $1\text{x}10^8$	Difference (g CO_2) $1\text{x}10^8$
Original	23.78	0
LRE	8.70	-15.08
LRE-B	8.66	-15.12
LRE-S	7.83	-15.95
LRE-S-B	7.80	-15.98
IRE	23.78	0

2.4.2 Project Economic Viability

The economic viability of the project is examined by calculating the simple payback period (SPP) for each case. There is a large range in the values for the SPP, ranging from 17 to 83 years.

This large range is due to the difference between each case and the original yearly electricity cost.

There are four main groupings where the SPP is either the same or extremely similar, which can be attributed to two factors: if the renewable energy was treated as an independent system or used locally and whether the HOEP or the FIT structure was used. The HOEP structure models have longer payback periods, as it does not include any government incentives and only looks at market values for the sale of the electricity. When the HOEP structure is used for a GEH that treats renewable energy as an independent system, there is no economic viability as the SPP is 83 and 82 years.

When the electricity is used locally first the SPP is reduced to 28 or 29 years. This large reduction primarily comes from the fact that locally produced and consumed electricity would not be subject to any of the auxiliary or generation fee charged by any provincial generator or distributor. The auxiliary fees can make up over 50% of the price paid by consumers. The SPP was lowered to 28 years by increasing the amount of electricity by shifting the electrolyser load to utilize more local electricity. The further increase in local energy use causes a reduction in auxiliary fees paid and the overall yearly cost of electricity.

By introducing government incentives through programs such as the FIT program the SPP can be reduced. When using local energy first and selling the surplus under the FIT program the SPP was 21 years for all cases, however by treating the two systems as independent the SPP can be further reduced to 17 years. This can be explained by the large price differential between the fixed FIT pricing structure and the variable HOEP price. By selling the electricity and purchasing the same electricity back at a lower price the structure favours the consumer.

Table 9: Simple payback period for each case

Case	SPP
IRE-HOEP-S	83
IRE-HOEP	82
LRE-HOEP	29
LRE-HOEP-B	29
LRE-HOEP-S	28
LRE-HOEP-S-B	28
LRE-FIT-S-B	21
LRE-FIT-S	21
LRE-FIT-B	21
LRE-FIT	21
IRE-FIT-S	17
IRE-FIT	17

2.4.3 Energy Storage Benefits

Energy storage, though when looking at the system is whole plays minimal effect, does independently have a much smaller SPP when using the HOEP pricing structure. By examining the savings associated with the addition of energy storage and the repurposed LIB capital cost the individual SPP is calculated. The savings created relative to the capital investment are much higher than the other systems in the GEH. This scenario causes payback periods that are much more acceptable.

Both while shifting the electrolyser load and while not the SPP is less than 10 years, Figure 10. By adding one pack to the GEH energy savings would allow for a SPP of 9 years while not load shifting and 8 years while load shifting. With the addition of a second pack the SPP equalizes and is 6 years for both instances. When the number of packs is increased past 4 packs, not load shifting produces more opportunities for energy storage savings and the SPP becomes 5 years.

By assuming an energy storage lifetime of 10 years the IRR of the energy storage system can be calculated [16] [11]. The system shows high payback periods after a minimum of two packs are used, Figure 11. Though it was seen that more savings from energy storage could be seen without shifting, it is important to remember that ca. \$50,000 in savings can be seen from electrolyser load shifting that requires no capital investment. This savings from shifting is significantly greater than the capital investment of even 8 repurposed battery packs. This therefore shows that adding repurposed packs post load shifting would still be an economically viable addition to the GEH. The additional reduction of GHG emissions of 3.46×10^6g CO_2 also makes a strong case for the project as an emission reduction project.

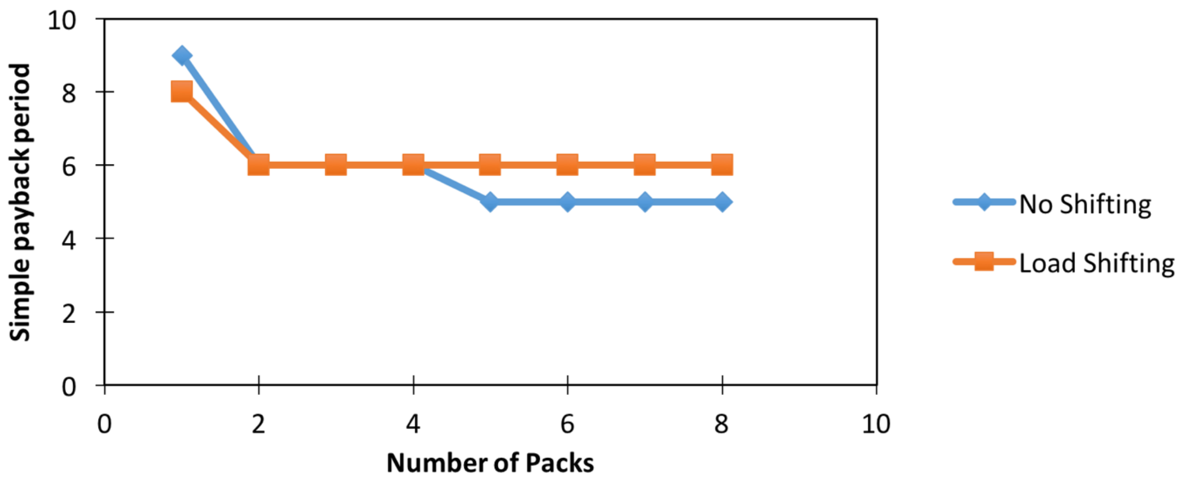

Figure 10: SPP of multiple 24kWh packs in the GEH

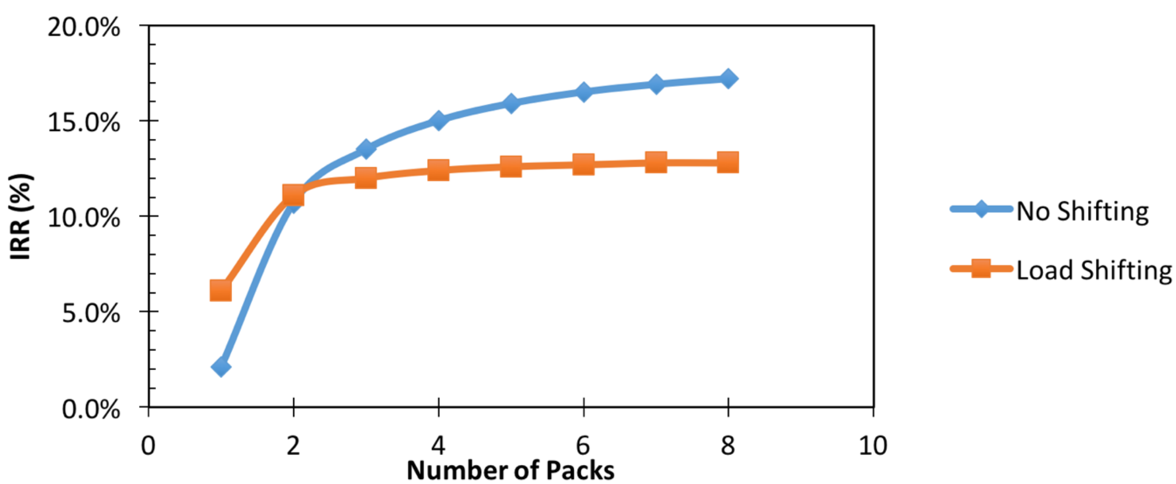

Figure 11: IRR of multiple 24kWh repurposed battery packs in the GEH

Though savings can be seen by the addition of energy storage with the HOEP pricing structure the opposite is true under the FIT pricing structure. By storing electricity with energy storage the consumer loses income from the fixed FIT selling price. With each addition of a repurposed battery pack there is a decrease in savings that can be seen, Figure 12. Under a FIT pricing structure energy storage becomes not economically viable, though similar savings in GHG emissions would still be seen.

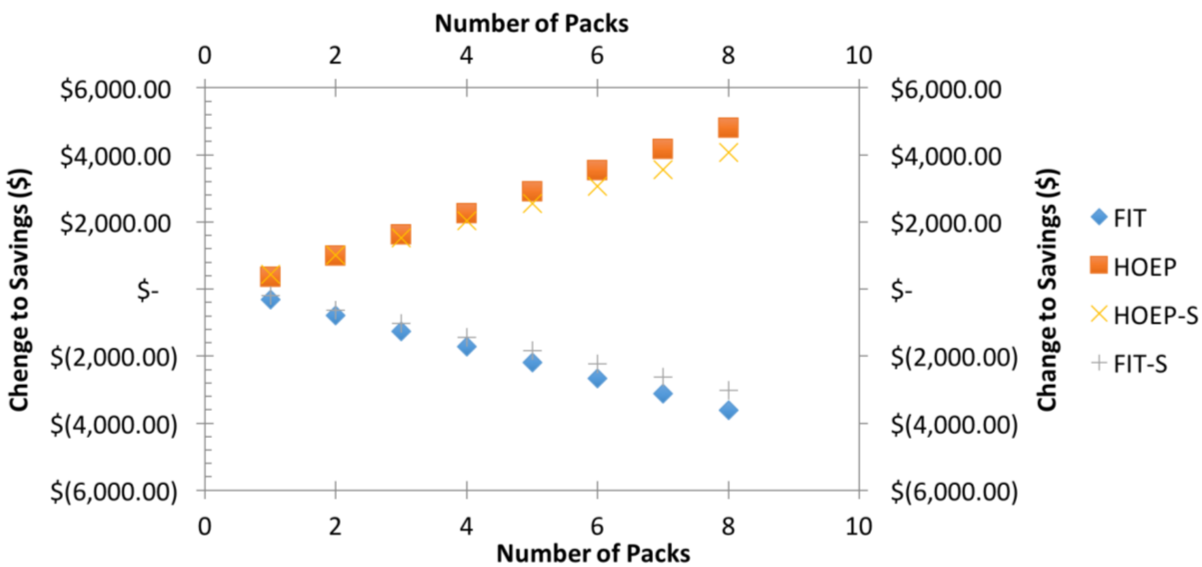

Figure 12: changes to savings with each repurposed battery pack added (solid shapes are without load shifting)

2.5 Conclusion and Policy Implications

Using a free market pricing structure, such as the HOEP, can produce cost savings. By making the GEH more efficient in its use of electricity by using local electricity, shifting the electrolyser load to decrease grid reliance, and implementing energy storage the yearly electricity cost can be significantly decreased. The high capital cost however still requires payback periods greater than 20 years with the HOEP model, though less than 30 years. Under the current FIT program, the consumer's electricity consumption program becomes a source of revenue income. With a negative yearly electricity cost the program is able to achieve payback periods less than 20 years. The GEH however does not gain any GHG emission reduction due from an LCA perspective when examining the consumption of electricity under the Scope 2 approach, while reducing the province wide Scope 1 emissions.

It is widely known that the problem of intermittency must be solved and that energy storage provides a possible solution. However current programs such as the FIT program in Ontario are a deterrent to the creation of micro grids and green energy hubs that optimize the efficiency of energy generation and consumption. The more storage added under a FIT model the fewer saving would be seen, Figure 12. The program therefore promotes renewable energy in Ontario while destabilizing the grid and promoting inefficiencies. This destabilization has caused an increase in energy prices and waste in the system as large amounts of electricity must be sold at negative prices to elevate the excess generation.

Ontario is currently examining the FIT program for projects such as this that have a capacity greater than 500kWh. Though incentives should still be examined to promote and expand the use of renewable energy, an effort to create a program that promotes efficiency, energy storage, and the use of micro grids to create a more sustainable future should be explored. Investigation into incentive programs such as capital cost investments, renewable energy company investments, or green project tax credits that move away from the "per use" program such as the current FIT program should be further studied. Further studies that examine different incentive models as well as different building load profiles will be examined to explore the possibilities of green energy hubs and micro grids in Ontario.

Chapter 3: HYDROGEN MARKET MECHANISMS

The following chapter details the work during my thesis which culminated into a paper published in the International Journal of Engineering and Science under the title "Market mechanisms in Power-to-gas" in 2016. The work was written by me with the support of the other authors including Dr. Sean B. Walker who assisted with the introduction, Dr. Michael Fowler who aided in editing the work, and Ushnik Mukherjee who provided background material. All authors have given approval for use in this thesis as the concepts and ideas are solely my own.

The chapter outlines different pricing structures for hydrogen. The analysis is completed by comparing to other energy markets such as natural gas, conventional hydrogen, and ethanol. The pricing demonstrates that a Power-to-gas facility can be profitable and can be implemented as part of different markets immediately.

3.1 Methodology

This analysis of the Power-to-gas facility is completed using two low fidelity user-built MATLAB functions. The model considers how a facility with Polymer Electrolyte Membrane (PEM) fuel cells would interact with the power grid and the associated performance, revenue, and cost. More specifically the model is used to determine the viability and profitability of a Power-to-gas system in Ontario between 2011 and 2013. The data is obtained through Ontario electricity system operators, which archives information including hourly, demand, generation, and price [58].

3.1.1 Plant Operation Function

The plant operation function determines both the electricity use and the quantity of hydrogen produced. The algorithm operates by defining specific input characteristics as well as logic parameters for the facility. These factors include the capacity, minimum and maximum operating percentage, and the electricity pricing information. These factors work together, Figure 13, to produce results that are examined in additional functions.

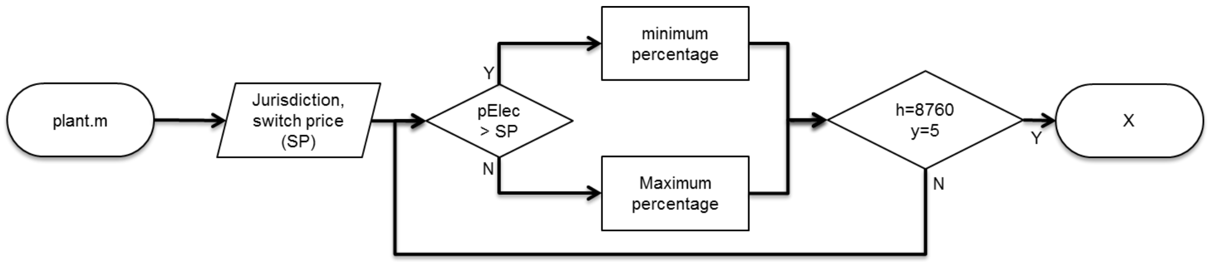

Figure 13: Logic for the determination of plant operation and production

The authors examine the effect of plant size by simulating a 5, 20, 30, and 40 MW plant. These facilities have a capacity to produce between 960 and 7690 Nm^3 of hydrogen per hour, which is the equivalent of 11 and 93 mmBTU of fuel, respectively. In this model, only the base electricity price influences when the facility operates at the minimum and maximum operating percentage. The plant's operation is determined by a switch price, determined by the authors, which is built into the function shown in Figure 2. The switch price determines when the plant operates at the maximum or minimum operating percentage. This means that when the base electricity price is less that the switch price, the plant operates at the maximum operating percentage to maximize the production and take advantage of low operational costs. Inversely, when the base electricity price is above the switch price the plant operates at the minimum operating percentage to minimize the impact of higher operational costs. Although PEM electrolyzers can be varied from 0 to 100%, a more moderate power range of 5% to 93% is used in the model [59].

In this analysis, two different scenarios are explored: the reduction of exports and low price hydrogen production. These scenarios differ in the switch price that is used in the simulation logic. In the first case, 0 CAD per MWh is used as a switch price to examine the benefits of using

Power-to-gas to eliminate losses due to electricity exports within a given jurisdiction. The plant would take advantage of the negative base electricity price and, as the cost goes negative when there is a surplus of electricity and larger exports are required, aid the jurisdiction by utilizing more electricity internally. In addition, with proper storage, the energy stored in the form of gaseous hydrogen could be utilized later and provide additional benefit by reducing sunk costs associated with exports.

In the second case a switch price of 40 CAD per MWh is used, which is above the weighted average price of the Hourly Ontario Electricity Price (HOEP), 30 CAD per MWh, over the three-year period examined. This is case is used to examine the benefits increasing the time the plant operates at a higher operating percentage. This scenario is applicable for many applications explored in our team's other works.

These scenarios, summarized in Table 10, are run through the same function using the parameters previously stated. Utilizing the switch price as the control logic, each hour in the years 2009 to 2013 are examined to determine the amount of hydrogen produced. To keep the size of the matrix and to allow for proper year over year evaluation leap years have been removed. For each hour the function determines the amount of hydrogen produced in the hour using the maximum and minimum operating percentage. Should the plant switch between the two operating percentages, a weighted average is used to determine the hydrogen production. The hydrogen is then stored in a three dimensional matrix in the form of power consumption (kWh), volume (Nm^3), mass (kg), and energy (mmBTU). The matrix can then be used in post processing for financial calculations.

Table 10: Power-to-gas facility scenarios examined

Name	Scenario	Focus
5MW$0	5 MW capacity with a switch price set at 0 CAD per MWh	Reduction of electricity exports
20MW$0	20 MW capacity with a switch price set at 0 CAD per MWh	
30MW$0	30 MW capacity with a switch price set at 0 CAD per MWh	
40MW$0	40 MW capacity with a switch price set at 0 CAD per MWh	
5MW$40	5 MW capacity with a switch price set at 40 CAD per MWh	Production of hydrogen
20MW$40	20 MW capacity with a switch price set at 40 CAD per MWh	
30MW$40	30 MW capacity with a switch price set at 40 CAD per MWh	
40MW$40	40 MW capacity with a switch price set at 40 CAD per MWh	

3.1.2 Financial Calculation Function

A MATLAB function is used to determine the feasibility of the system by examining the different market mechanisms that must be utilized. This is done in a two-stage process outlined in Figure 14. First, a profit matrix is created in which the yearly base electricity cost, additional electricity fees, operational cost, and revenue from hydrogen production from 2011 to 2013. This matrix is then manipulated to determine the average yearly profit.

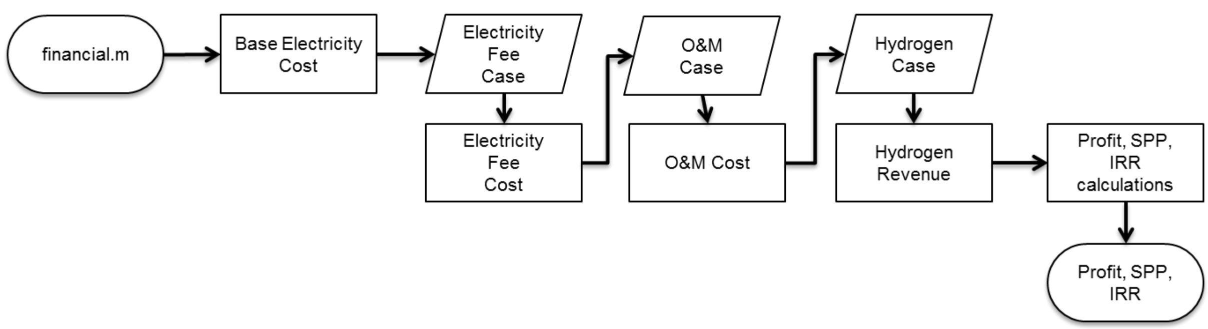

Figure 14: Logic for the calculation of financial viability of specific market mechanisms

The base electricity price and maintenance costs are constant when examining the different market mechanisms. Though the code is designed to accommodate any 5-year period where hourly data is available, only the HOEP is considered in this work. Considering only the HOEP allows the impact the market mechanisms on the profitability of the Power-to-gas facility to be considered. Operating and maintenance fees have been set to 0.00446 CAD per MWh [60]. This operating and maintenance fee does not include electricity. These constant parameters are used in each scenario and case for the 5-year period.

An additional electricity fee is charged to account for transmission and distribution charges. In 2012, a review of the export tariff for electricity exports was prepared for the IESO. The export tariff at the time was 2 CAD per MWh, and was under review [61]. One option was to set the tariff to the Equivalent Average Network Charge (EANC), which is equal to 5.8 CAD per MWh [61]. As the electricity for the plant is used internally to the jurisdiction the EANC is used as an additional market mechanism for the electricity fee cost. The cost is calculated for each year from 2011 - 2013.

Market mechanisms that treat hydrogen solely as an energy source and as a product are considered in this work. Utilizing Henry Hub data obtained from the US Energy Information Administration (EIA) for the monthly natural gas price for the examined time period hydrogen can be sold for its energy value [62]. The monthly mmBTU is calculated for each year and the revenue from selling hydrogen for its energy value is calculated.

Hydrogen can also be sold as a product on a mass basis. Utilizing data from the Department of Energy, a current price of 5.08 CAD per kg is considered [63]. This is equivalent to the total hydrogen cost, and includes production and dispensing. This mechanism is used to see if a POWER-TO-GAS system with this structure can be competitive with SMR hydrogen production and industrial hydrogen practices.

Hydrogen can also be sold for its renewable alternative energy value by examining the price of ethanol. The current price of ethanol is 2.58 USD/gal, which is equal to 30.47 USD/mmBTU [64]. By selling the hydrogen at this price, the energy value of both renewable alternative fuel sources is explored.

After the profit is determined, the capital costs and viability are determined. Capital costs are calculated based off numbers given by the industrial partners. The capital cost is calculated by setting the low-end cost to 1.5 USD per MW and 1.25 USD per MW installed for a 5 and a 40 MW plant respectively. The capital cost is then interpolated to obtain the investment for the in between plant sizes. Utilizing this profit matrix and the capital cost the function calculates the simple payback period (SPP) and the internal rate of return (IRR). A lifetime of 10 years is used in this work to calculate the IRR [60]. The results are then used to compare the viability of the different mechanisms summarized in Table 11.

Table 11: Market mechanisms examined in financial simulations

Parameter	Market Mechanism	Value
Electricity Base Price	Hourly Ontario Electricity Price	IESO hourly data [58]
Electricity Fees	Equivalent Average Network Charge	5.8 CAD/MWh [61]
Operation and Maintenance	Operation and Maintenance excluding electricity	4.5×10^{-3} CAD/MWh [60]
Revenue	Natural Gas Energy Price	EIA Henry Hub Monthly data [62]
	Industrial Hydrogen Price (SMR)	4.68 CAD per kg [63]
	Ethanol Energy Price	33.90 CAD per mmBTU [64]

3.2 Results and Discussion

Each scenario is analyzed utilizing the natural gas energy value, industrial hydrogen produced by SMR, and ethanol hydrogen market mechanisms. Different characteristics of the plant are examined for the scenario as well the financial viability of each case. This allows for an examination of the systems and mechanisms that need be put in place for Power-to-gas systems.

3.2.1 Plant statistics and cost

The basic plant characteristics do not vary with plant capacity but rather the set point, or switch price that the facility switches between the maximum and minimum operating percentages. When the switch price is set to 0 CAD per MWh the focus of the plant is to reduce undesired exports from the jurisdiction. During the simulation, the plant operated at maximum capacity only 2.7% of the time, or had a operating capacity of 0.027. Even though the plant primarily operated when the base electricity price was negative the average price is 8.9 CAD per MWh. This is positive because the plant operated at 5% capacity at all other times. Though the plant could operate at 0%, 5% is chosen to allow other services to be performed during the minimum operating capacity performance. When the focus shifts to the production of hydrogen both factors increase. The operating capacity increases to .924, or 92.4% of the simulation time. By operating at a higher switch price more hydrogen is created and sold with each market mechanism. The increased production does however have additional costs. The average base electricity price at this switch price is 23.1 CAD per MWh which is 2.6 times higher than the previous scenario.

As illustrated in Table 4, though the operating capacity does not change with the plant size the costs associated with electricity and operation and maintenance and the costs increase linearly with plant capacity. For a .027 operating capacity the total cost is 12,216 CAD per MW, in which the base electricity costs accounts for 46% of the cost. When the operating capacity increases to .924 the total cost increases to 32,622 CAD per MW. This increase in expense is due to the increase in average electricity price and hydrogen production, causing the percent cost associated with the base electricity price to increase to 69%. The ratio between the additional electricity fees and operation and maintenance fees is constant for all operations.

Table 12: Base costs for each scenario including base electricity costs, additional electricity fees, and operating and maintenance costs in CAD

Operating capacity	**.027**				**.924**			
Plant Size	5	20	30	40	5	20	30	40
Base Electricity	28,383	113,530	170,295	227,060	844,723	3,378,894	5,068,341	6,757,788
Electricity Fee	188,487	73,946	110,919	147,892	212,186	848,745	1,273,117	1,697,490
O&M	14,211	56,843	85,265	113,686	163,110	652,439	978,659	1,304,878
Total	61,080	244,319	366,476	488,639	1,220,019	4,880,078	7,320,117	9,760,156

3.2.2 Hydrogen revenue mechanisms and profit

Hydrogen is sold for the equivalent price of Natural Gas (NG), industrial hydrogen (SMR), and ethanol. These different market mechanisms produce different revenues for the facility. The two market mechanisms sell hydrogen for their energy value produce very different results. The NG mechanism revenue is approximately one tenth of that of the ethanol mechanism as the price is significantly smaller. The revenue from NG pricing ranges from ca. 26,000 to 210,000 CAD and 300,000 to 675,000 CAD for a .027 and .926 operating capacity respectively. This revenue is already lower than the total operating costs of the facility making this mechanism not viable, as there is a negative profit. The revenue from ethanol pricing ranges from ca. 250,000 to 2,000,000 CAD and 2,900,000 to 23,000,000 CAD for a .027 and .926 operating capacity respectively. This revenue is above the total operating costs and is further explored later in this work.

Hydrogen is also sold as an industrial hydrogen alternative, utilizing the given DOE current costs of SMR hydrogen [63]. This hydrogen market mechanism gives the highest revenue, ranging from ca. 260,000 to 2,100,000 CAD and 3,000,000 to 24,000,000 CAD annually for a operating capacity of .027 and .926 respectively.

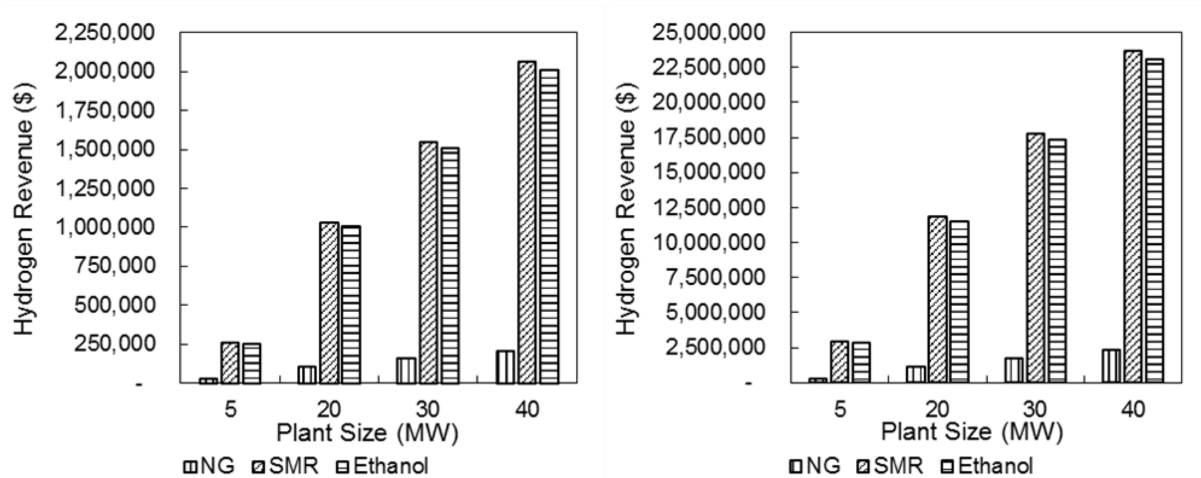

Figure 15: Hydrogen revenue for each market mechanism at .027 capacity (left) and .926 (right) operating capacity

The resulting profit is calculated from the costs in the previous section and each hydrogen market mechanism. The revenue when only a .027 operating capacity is used is significantly smaller than when a operating capacity of .926 is used. This is due to the significantly larger quantity of hydrogen produced with a less significant increase in average base electricity price. The profit ranges from 190,000 to 1,600,000 CAD and 1,650,000 to 14,000,000 CAD for each operating capacity respectively.

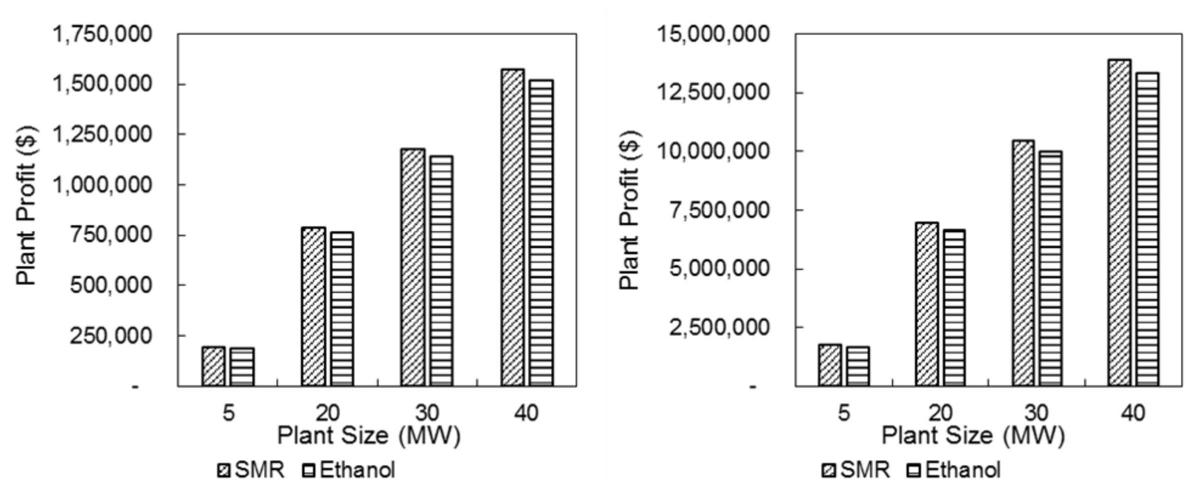

Figure 16: Plant profit for each market mechanism at .027 capacity (left) and .926 (right) operating capacity

It is important to note the impact that such pricing can have if the hydrogen is injected into the NG grid as is proposed in the Power-to-gas project. By limiting the amount of hydrogen to 5% by volume, due to piping concerns, the energy percentage is limited to 1.6% by energy hydrogen. The result means that thought the hydrogen market mechanism would be selling energy that is 10 times higher than NG, the weighted average price would only increase 13%, from 3.89 CAD to 4.39 CAD. The mixed gas product could then be sold as renewable natural gas at a premium of at least this percentage.

3.2.3 Market mechanism viability

The market mechanism viability is determined from the Simple Payback Period (SPP) and the Internal Rate of Return (IRR). Since the NG market mechanism is unable to generate positive profits, it is no longer considered in this work. Both the SMR and ethanol market mechanisms produce positive profits and are detailed in Table 5 below. The SPP for a .027 operating capacity are higher than the expected lifetime. The profit is too low and the SPP is significantly higher. This makes a low operating capacity not a viable option as the plant would not make its return on investment within the 10-year period. So though the market mechanism seems viable it cannot be used. The SPP for a .924 operating capacity however creates substantial profit to see reasonable SPP. The SPP ranges from 5 years at low capacities to 4 years at high capacities. The SPP is not flat due to the lower per MW plant cost at higher plant capacities. By function of design the plant will always do better the larger the plant is.

Table 13 Simple payback period for all scenarios with NG and ethanol market mechanisms

Operating capacity of electrolizer	**.027**				**.924**			
Plant Size	5	20	30	40	5	20	30	40
SMR	42.5	39.4	37.4	35.4	4.8	4.5	4.2	4.0
Ethanol	43.9	40.8	38.7	36.6	5.0	4.7	4.4	4.2

The IRR for a .924 operating capacity ranges from 16% to 21% and 15% to 20% for SMR and ethanol mechanisms respectively. The plant is profitable and viable with either of the two hydrogen market mechanisms with only a 1% difference at each capacity. Selling hydrogen as a commodity, or for its equivalent renewable energy value are both possible market mechanism that can be pushed for by POWER-TO-GAS plant companies.

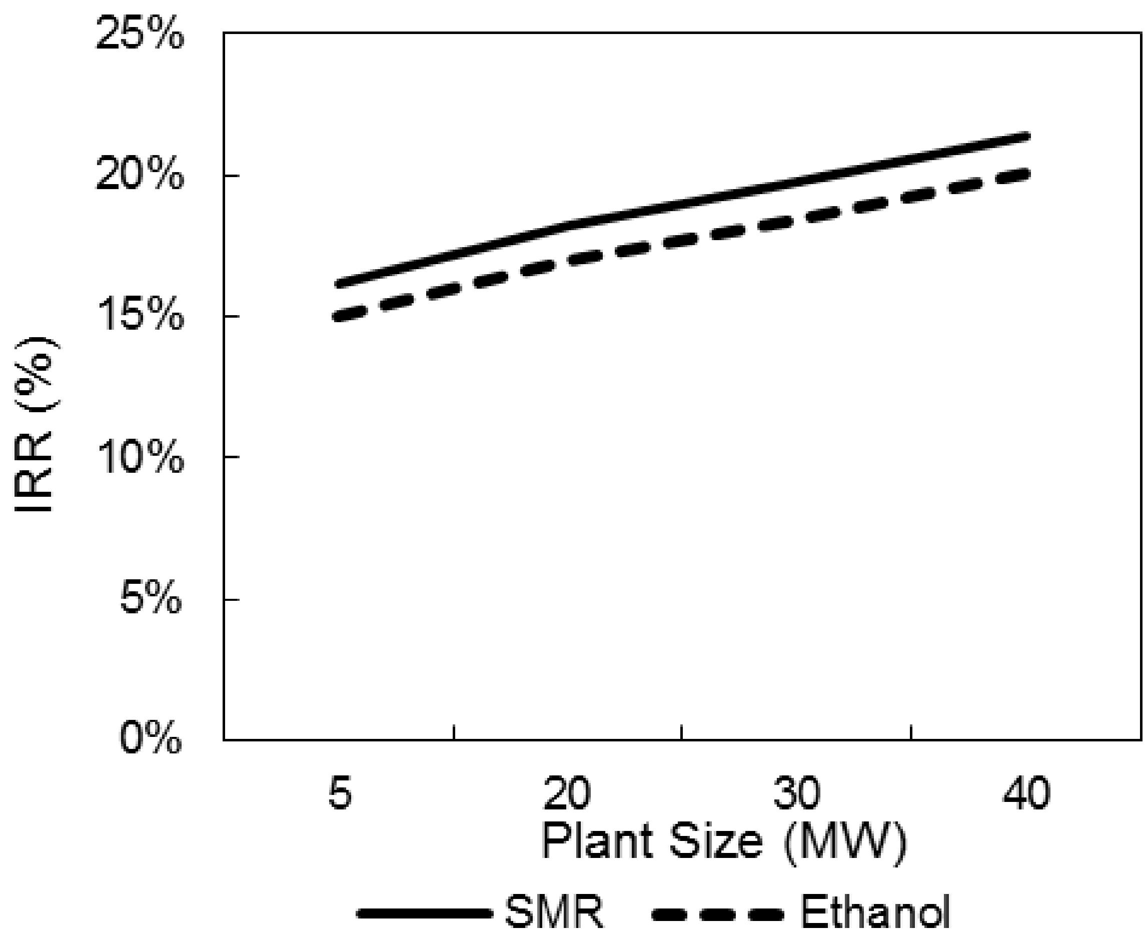

Figure 17: Internal rate of return for SMR and Ethanol at .924 operating capacity

3.2.4 Additional revenue sources

Although there are potential profitable streams if industrial hydrogen or ethanol pricing is used, the use of natural gas pricing or of a disadvantageous switch price would lead to the necessity of adopting government incentives or finding alternative funding sources. As Power-to-gas can be injected into natural gas pipelines to create HENG, which burns cleaner than conventional natural gas or used for fuel in an emissions free hydrogen vehicle, there is an opportunity for funding based on environmental performance. One option is the use of carbons credits for the CO_2 that is offset by the use of Power-to-gas [65]. This option rewards the hydrogen producers to offset operation costs and rewards consumers of hydrogen by offsetting the high prices asked by producers. Other programs encourage investment in environmentally sound projects by offering relief in ongoing costs. An example of this is that is often used in housing projects is tax increment-based financing which provides an alleviation in taxes equal to the capital investment of the project [66]. In California, a self-generation incentive program is used to provide a government contribution to the cost of installing renewable energy projects, like clean hydrogen projection [67]. More consumer-directed incentives, such as the Ontario Clean Energy Benefit aim to encourage energy users to use renewable energy by changing their energy use patterns through reduced energy costs [68].

3.2.5 Additional benefits

In addition to significant economic gains, Power-to-gas is able to provide flexible energy storage. As shown in Figure 1, hydrogen can be produced from an electrolyzer or from agricultural feed. This gas can then be stored with natural gas to form HENG. Due to the enormity of natural gas infrastructure available in Ontario, it is conceivable that years' worth of energy could be stored as hydrogen making up only a portion of this space. This length of storage time separates Power-to-gas from competing technologies and could allow the grid operator to manage periods of prolonged surplus or deal with increased loads caused by extreme weather events. The flexibility of the hydrogen generation technology also means that Power-to-gas can be used to provide frequency regulation services to the grid. In these instances, the electrolyzer power would be reduced when the grid demand is high. In 2014, IESO performed tests to verify the electrolyzers produced by Hydrogenics could be ramped up and down quick enough to provide ancillary services [69].

3.3 Conclusions

Power-to-gas facilities show potential to provide substantial benefits to power grids, providing increased grid management as well as important auxiliary services. The market mechanisms for how the facility that created hydrogen in a Power-to-gas system have not yet been determined but are an important to determine the viability of Power-to-gas systems. Though hydrogen cannot be sold for its energy value at the natural gas price, other mechanisms that compare the hydrogen product with industrial steam methane reformed hydrogen as well as renewable ethanol show the projects can be viable. This is only true however if higher operating capacities are used, meaning the facilities focus cannot solely be the reduction of exports. With high operating capacities and appropriate market mechanisms internal rates of return between 15% and 21% are seen showing the project viability. These mechanisms should therefore be pushed when speaking with governments and organizations on policy matters in addition to all the additional benefits, including energy storage, to show the large impact a Power-to-gas system has.

Chapter 4: HYDROGEN AS A TRANSPORTATION FUEL

The following chapter details the work during my thesis which culminated in a paper to be soon published. The work was written by me with the support of the other authors. All authors have given approval for use in this thesis as the concepts and ideas are solely my own.

The following chapter examines hydrogen as a transportation fuel when created through Power-to-gas. The model examines the incentives that have been applied to ethanol by the government to hydrogen. The case is made that the since the emission reduction potential of Power-to-gas hydrogen is greater than ethanol that the same subsidy to ethanol should be applied to hydrogen. Other fuels are also examined.

4.1 Methodology

This analysis builds off previous work and expands to allow for more flexibility in the operation of a Power-to-gas facility [19]. The model considers a Polymer Electrolyte Membrane (PEM) electrolyzer, which uses electricity from the Ontario power grid. In addition to examining the performance, revenue, and profitability of the Power-to-gas system, the emissions from the electrical load of the hydrogen plan are considered in order to analyze the emissions of using hydrogen for transportation.

Emissions reductions associated with using hydrogen as a fuel are obtained through the emission reductions that arise from the production of hydrogen and from driving vehicles that utilize hydrogen as a fuel. In this analysis, diesel vehicles are compared with dual-fuel diesel/hydrogen co-combustion vehicles and with hydrogen fuel cell vehicles (HFCVs). To understand how to incentive the use of emission-reducing green hydrogen, an examination of the incentives used to support the production of bio-ethanol under the Renewable Fuel Standard.

4.1.1 Plant Operational Parameters

To determine the hydrogen production a script is used to determine how much hydrogen is being produced at each hour from 2011 to 2013. To initialize the script the facility parameters must be know. First, the capacity of the plant is set to 40MW. This capacity allows the facility to generate up to 7690Nm^3 of H_2 per hour which is sufficient to supply 9714 vehicles for their daily commute or could be used in a more integrated system as shown earlier.

The second parameters required are the minimum and maximum operational limits of the system. PEM fuel cells offer improved operational parameters than alkaline fuel cells as they can be varied between 0 and 100 percent while operating [59]. A more moderate power range of 5 to 93 percent is used in this model as it was used in previous studies [19].

With the plant parameters defined, the operational parameter can be chosen. In previous works, this was a cost threshold, which was an electricity price at which the plant operated at the minimum operational percentage when the electricity price is above the value at the maximum operational percentage when the price is below the value. In this analysis, however two different scenarios are used to examine how the facility can be used with either cost or emissions in mind to produce a desired result. Therefore, two threshold values are used as an input and are based on the Hourly Ontario Electricity Price (HOEP) and the Hourly Ontario Emissions Factor (HOEF).

The first scenario is the cost scenario and a threshold price is used in conjunction with the HOEP tabulated between 2011 and 2013. When the cost scenario is selected, the script requires the user to input the value desired to use to determine when the plant operates at minimum and maximum operating percentages. Using this switch value, the script calculates for each how the amount of electricity used hydrogen produced for each hour.

The second scenario is the emissions scenario and the HOEF is used with all data tabulated between 2012 and 2013. The data could is not tabulated for 2011. When the emission scenario is selected the script requires the user to input the value desired and the script runs in the same why as in the cost scenario. When the script is complete, the amount of hydrogen is outputted to be further analysed.

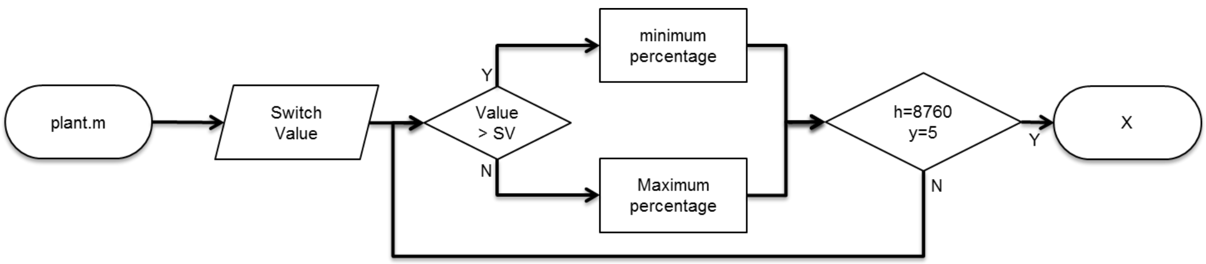

Figure 18: Logic for the determination of plant operation and production

4.1.2 Switch Value Analysis

In order to compare properly the two scenarios, different cases for each scenario are run to analyse the cost and emission impact. As previously mentioned, the model can be controlled based on either of these parameters using a switch value to turn the system on and off. These allow for the examination of both economically and environmentally driven simulations.

For economically driven simulations, the HOEP is examined to determine the switch value. In order to achieve a capacity factor close to 50% to the median HOEP is used as a base case. This was determined to be $25.68 per MWh. The average price however is slighter higher than the median due to the high peak energy prices causing a tail in the frequency distribution as shown in Figure 19. The mean HOEP between 2011 and 2013 is found to be $25.98 per MWh and is used as the second cost-based scenario. As demonstrated in previous works however it can be economically desirable for the facility to operate at a higher capacity factor. For this reason, the third cost-based scenario is to utilize a switch value that is equal to the mean plus one standard deviation, which is determined to be \$47.00 per MWh.

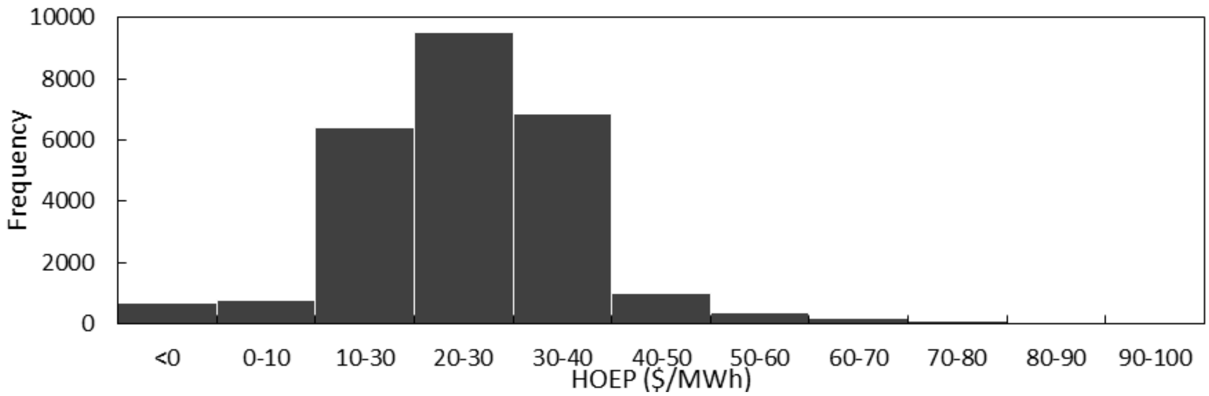

Figure 19: Frequency distribution of Hourly Ontario Energy Price from 2011-2013

For the emission driven simulations, the same scenarios are used. As a base case, the median is used as the switch value for facility operation at maximum and minimum capacity. For the province of Ontario between 2012 and 2013, the median emission factor is 87kg of CO_2e per MWh. This relatively low emission factor is due to the nature of the power grid, which consists of over 50% nuclear and hydro, which are both low emitting power generation methods. When examining the mean emissions factor in the emission scenario there is more of a deviation from the mean. The mean is found to be 95kg of CO_2e per MWh, which is an increase of 8kg of CO_2e per MWh. For the final case, the mean plus one standard deviation was also used, to demonstrate the economics of more frequently operating the facility. This emissions threshold is evaluated to be 142kg of CO_2e per MWh.

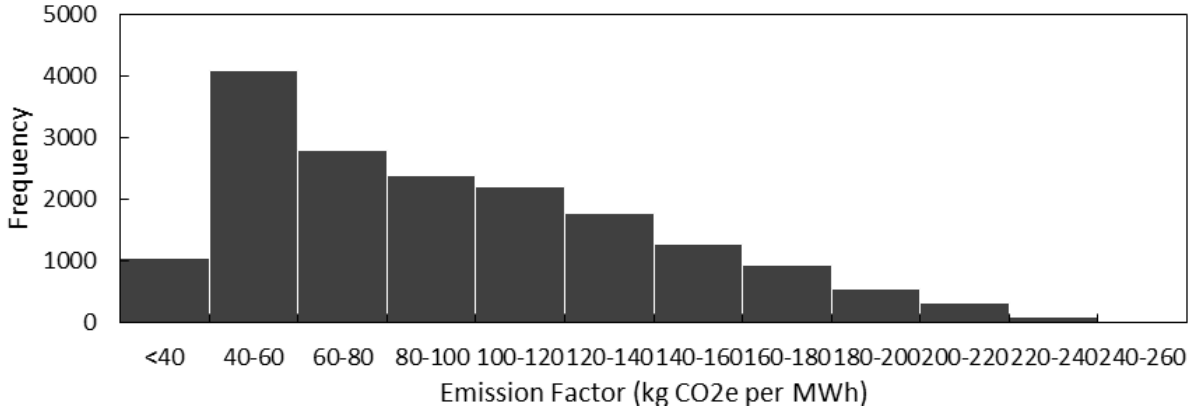

Figure 20: Frequency distribution of emission factors from 2012-2013 for Ontario

4.1.3 Plant Financial Parameters

Once the plant output of hydrogen is determined and the electricity consumed quantified the economic analysis of the scenarios are examined. To do this the base electricity cost, electricity cost, operational and maintenance cost, hydrogen selling price, and other revenue are calculated. This is completed for each year examined and the average between all years is used as the yearly profit.

The electricity costs are determined through the HOEP and an Equivalent Average Network Charge (EANC). The HOEP is already collected between 2011 and 2013 and is therefore multiplied by the electricity consumed by the facility. The HOEP is used as the case study examines a facility in Ontario. In Ontario, there are additional fees associated with electricity that can be used instead of the EANC, such as the Global Adjustment charge. The EANC is used however as in previous works the argument was made that energy storage facilities, which aid in the management of the jurisdictions resources, should only be charged the same as exporters which in a report was argued should pay the EANC [19] [61]. This EANC is equal to $5.8 per MWh and is applied based on the electricity consumed. The final cost considered is an operating and maintenance fee of $0.00446 per MWh [60]. Two revenue streams are examined in this work, revenue from selling hydrogen and revenue from government incentives. Though producing cheaper hydrogen can be desired, previous works showed that a facility can be profitable if a Steam Methane Reformation (SMR) hydrogen price is used [19]. Utilizing data from the Department of Energy, a price of $5.08 CAD per kg is considered to determine the revenue from selling of hydrogen [63].

As discussed previously there are currently incentives for ethanol as a transportation fuel, from the federal government in the United States. These incentives are to offset the cost of ethanol and create a market for ethanol fuel. Hydrogen for transportation is another greenhouse gas reducing alternative fuel that can be used in automobiles. If a policy were to extend its alternative fuel coverage to hydrogen, it would help create the hydrogen economy while achieving environmental goals.

To examine how an incentive similar to that of ethanol could be applied to hydrogen an energy equivalency is used. If a $0.46 per gallon subsidy is applied to ethanol than a $0.795 per kg subsidy could be applied to hydrogen. By applying the incentive based on an energy equivalency, the differences between the fuels can be eliminated. To examine the effect of the tax credit as an incentive the simulation is conducted both with and without the credit. This is in effort to show how the government can drive innovation and adapt a Power-to-gas system that can have environmental benefits. In order to justify the dollar value the emission reduction potential for both hydrogen and ethanol are examined.

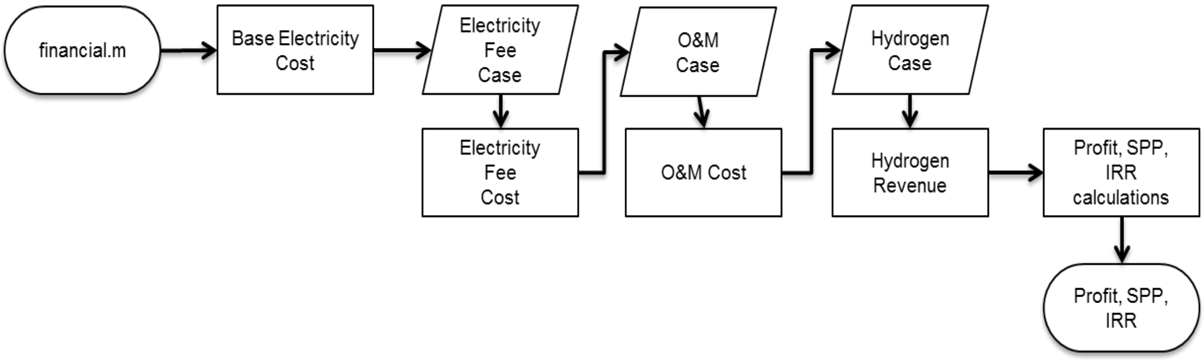

Figure 21: Logic for the calculation of financial viability of specific market mechanisms

4.1.4 Plant Emission Parameters

Using similar methodology in examining the financial parameters, emission factors for various molecules are determined. In addition to the HOEF, the emission factors for carbon monoxide (CO) and nitrous oxides (NOx) are also recorded from 2012 to 2013. Using this tabulated information the average CO, NOx, and CO_{2e} is calculated based on the total emissions from secondary emissions and the total amount of hydrogen produced. From the total emissions data it is possible to examine and compare the emissions of hydrogen production and use with other fuels, such as gasoline, diesel or ethanol during production and combustion.

The CO_2 emissions from the electrolysis of water to generate hydrogen are determined using electrical generation data. In Ontario, this data is available from the Independent Electrical System Operator [70], who operates the grid. Using this power generation data, in addition to emissions data for each type of power generation, a weighted average is taken to determine the amount of emissions per unit energy, measured in kg per MWh, during any given hour. Using the efficiency of the electrolysers, this can give the number of kg CO_2e per kg H_2. Due to the province's reliance on nuclear energy, and its elimination of coal power, the emissions factor for Ontario is lower than other provinces like Alberta.

4.1.5 Emissions Reductions

To determine the emissions reductions from using various fuels such as bio-ethanol, gasoline, diesel and hydrogen the analysis is broken down into well-to-pump and pump-to-wheel. In Table 1, for example, the well-to-pump emissions factors for two types of gasoline and corn ethanol.

Table 14: Gasoline and Renewable Fuel Blending [71]

Fuel	g CO_2e per MJ of fuel (well-to-product)
Gasoline	18.97
Oil Sands Gasoline	28.23
Diesel	17.10
Corn Ethanol	20.24
Biodiesel	20.25

Using this data as well as the drive phase, or pump-to-wheel phase data, the total lifecycle emissions of each fuel is compared.

4.1.5.1 Bioethanol Emissions

The blending of ethanol follows specific volumetric and energy rules. In Table 2, below, the properties of straight gasoline, 5% ethanol-gasoline mixtures (E5) and 10% ethanol-gasoline mixtures (E10) are shown. As the ethanol-gasoline mixture grades are based on volumetric percentages, the energy ratios vary slightly.

Table 15: Use Phase Emissions for Fuel Blends [71]

	Blend		Gasoline			Ethanol			
Fuel	**km/MJ**	**gCO2e per MJ**	**% MJ**	**km per MJ**	**gCO2e/MJ**	**MJ per km**	**% MJ**	**km per MJ**	**gCO2e per MJ**
Gasoline	0.39	67.47	100	0.39	67.47	2.56	0	-	40.53
E5	0.40	66.55	96.6	0.39	67.47	2.56	3.4	0.71	40.53
E10	0.42	65.61	93.1	0.39	67.47	2.56	6.9	0.85	40.53

The addition of ethanol to fuel is intended to provide greenhouse gas reductions, while securing the fuel supply and providing a renewable source. An issue raised by Searchinger [72] is that of the indirect land use changes that may mitigate some of the CO_2e savings attributed to biofuels. These indirect land use changes can vary between 20g CO_2e per MJ of fuel extracted to 100g

CO_2e per MJ of fuel [72]. By including the impact of land use change, it is possible to develop more accurate emissions factors, in gCO_2e per MJ, for different blends of gasoline and ethanol. Based on these blending properties, and using the emissions quantities cited above, ranges of life cycle emissions are given for different fuel compositions. As can be seen, depending on how much emissions are attributed to indirect land use change, the blending of renewable fuels with gasoline can result in a net loss or net gain of CO_2e emissions.

Table 16: Total Fuel Cycle Emissions for Blended Fuels [71]

Fuel	km per MJ	MJ per km	Gasoline Energy %	Ethanol Energy %	gCO_2e per MJ	Emissions Reductions gCO_2e per MJ
Gasoline - Conventional	0.39	2.56	100%	0%	86.44	
Gasoline – Oilsands	0.39	2.56	100%	0%	95.70	
E5 with Conventional Gasoline	0.401	2.49	97%	3%	85.85-88.56	-2.12 - 0.59
E5 with Oilsands Gasoline	0.401	2.49	97%	3%	94.84-97.55	-1.85 - 0.86
E10 with Conventional Gasoline	0.422	2.369	93%	7%	85.35-91.67	-5.23 - 3.21
E10 with Oilsands Gasoline	0.422	2.369	93%	7%	93.97-100.29	-4.58 - 3.58

Based on the Total Fuel Cycle Emissions for Blended Fuels, calculated from well-to-pump and pump-to-wheel data for ethanol and gasoline blends, provided by Argonne [73] and Gnansounou et al. [74], it can be seen that the overall emissions reductions are small and potentially even negative, depending on the type of fuel.

4.1.5.2 Hydrogen-Diesel Dual-Fuel

The blending of hydrogen with diesel, to generate a dual fuel, can have a significant impact on overall emissions. At full load conditions, Deb et al. [75] find that with an addition of hydrogen at increasing concentrations causes a correspondent 11%, 17%, 30% and 42% by energy content, emissions of CO_2 fell from 623 g per kWh to 510, 443, 324 and 248 g per kWh, respectively. The levels of NO_x, however, increase significantly with the increasing hydrogen concentrations from 2.5 g per kWh for pure diesel to 12.5 g per kWh when the mix contains 42% H_2 [75]. Lilik et al. [76] also found that brake specific NO and NO_2 emissions increased with the addition of hydrogen to the fuel mix. This increase in NO_x is likely due to the increase in combustion temperature that accompanies the addition of hydrogen into the fuel. The addition of hydrogen to the fuel mix may also cause a reduced fuel requirement for maintaining idling [77]. In Table 4, emissions data from three sources for diesel-hydrogen dual fuel engines is given.

Table 17: Collected emissions data for hydrogen-diesel dual fuel co-combustion

	km/MJ [71]	**gCO_2 per kWh** [75]	**gCO per kWh** [75]	**gNO_x per kWh** [75]	**gCO_2 per kWh (40% Load)** [78]	**gCO_2 per kWh (60% Load)** [78]	**gCO_2 per kWh (75% Load)** [78]	**gCO_2 per kWh (100% Load)** [78]
Diesel	0.38	623	1.76	2,8	862	898	932	924
11% H_2	0.38	510	0.78	9.0				
15% H_2	0.38	467 [77]						
17% H_2	0.38	443	0.73	9.2				
30% H_2	0.38	324	0.59	10.3	683	650	596	651
42% H_2	0.38	248	0.52	12.5				

Based on these tests, it can be seen that the addition of hydrogen to a diesel engine causes a significant reduction in CO_2 emissions while significantly increasing NO_x emissions. By combining the tabulated data from studies on dual fuel engines, with emissions data from Argonne National laboratory, it is possible to estimate emissions levels with different hydrogen concentrations. In Table 5, below, the emissions reductions of using a diesel-hydrogen dual fuel system is illustrated.

Table 18: Collected emissions data for hydrogen-diesel dual fuel co-combustion

	km/MJ	gCO2e per MJ	Emissions reductions	% reductions
Diesel	0.38	92.814		
11% H_2	0.38	75.979	16.835	18.1%
15% H_2	0.38	69.573	23.241	25.0%
17% H_2	0.38	65.998	26.816	28.9%
30% H_2	0.38	48.269	44.545	48.0%
42% H_2	0.38	36.947	55.867	60.2%

4.1.5.3 Hydrogen Fuel Cell Vehicle

The emissions for hydrogen fuel cell vehicles are dependent on the emissions from the production of hydrogen and not of its use during the drive-cycle. The emissions of generating hydrogen are dependent on the technology. For example, Steam Methane Reforming (SMR) produced approximately 9 kg of CO_2e per kg of H_2 produced [79], [80]. Producing hydrogen by electrolysis, however, is dependent only on the type of power generation is being used to generate the electricity. Using the methodology described in subsection 2.1, emissions reductions for each of the fuel types given here are determined.

4.2 Results

4.2.1 Electricity Price and Emissions

By varying the switch value for both scenarios, the average HOEF and HOEP change over the course of the three-year period. It is found that the largest degree of change occurred in the factor that was being controlled for by the switch value. That is to say, when the HOEF is being used as a switch value, the average HOEF changed with larger magnitude then that of the average HOEP. In addition, when the HOEP is being used as a switch value, the average HOEP changed with larger magnitude than that of the average HOEF.

This phenomenon allows one to operate with relative certainty of the other depending on the operational goal of the facility. If the goal is to reduce emissions then the electricity cost can be predicted within a certain realm of certainty. In this analysis, it is shown that though the HOEF varies between 61, 64, and 80 kg of CO_2e per MWh for the median, mean, and mean +1 standard deviation respectively, the HOEP only varies between \$19.08 and \$21.67 per MWh for the best and worst scenario. This shows that though the average emission factor increased by 31%, the electricity cost only increased by 14%.

Alternatively, if the goal is to limit cost, the average HOEF changes with smaller magnitude. The average HOEP varies between \$16.64, \$16.83, and \$23.71 per MWh for the median, mean, and mean +1 standard deviation respectively, the average HOEF only varies between 82kg and 94kg CO_2e per MWh for the best and worst scenario. However, the electricity price increased by 42%, the average HOEF only increased by 15%. This demonstrates that controlling the cost has marginally more of an effect on the average emissions than controlling the emissions has on the cost.

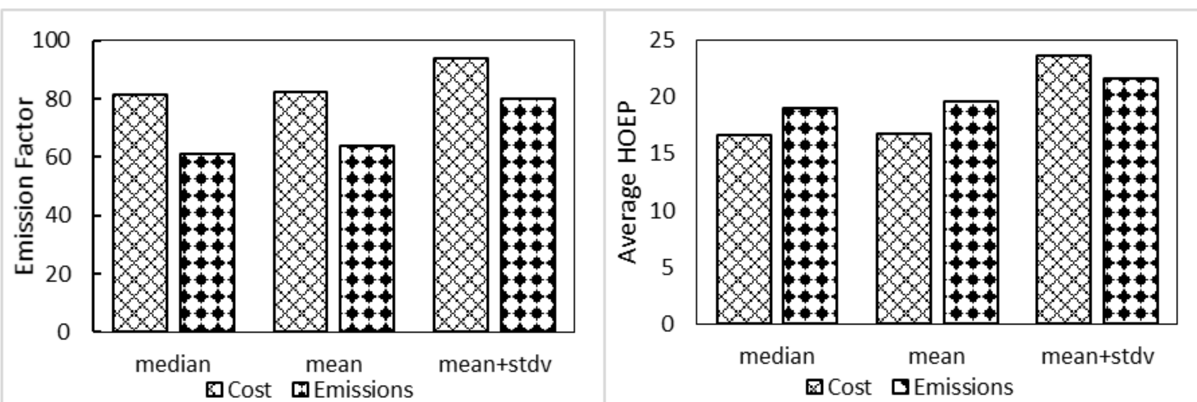

Figure 22: Average emission factor (left) and HOEP (right) utilizing both cost and emission switch values of the median, mean, and mean plus one standard deviation

By distinguishing between the two scenarios, cost and emissions, a system can be set up to meet the needs of the market. With greenhouse gas emissions being of great importance, being able to control the secondary emissions from electricity generation can be of great benefit. It also is of great benefit when considering the well to tank emissions of the fuel sources. By utilizing renewable and low emitting electricity, renewable and low emitting hydrogen is created. This can help the jurisdiction have an integrated emission reduction strategy, as both hydrogen generation and use are a greater improvement over conventional fuels than ethanol.

4.2.2 Financial Results

Both emission and cost scenarios show positive results that prove the economic viability of such a project. This is shown by examining the simple payback period and the internal rate of return. The payback period is what is often used to determine project viability. However, with long-term projects the internal rate of return can be used to approximate the lifetime return on investment. Given the 20-year life span of PEM fuel cells, the internal rate of return is used to compare the viability of the project.

In examining the both cost and emission scenarios without the ethanol tax credit the SPP and IRR show promising results. The emission scenario with the median case produces the worst SPP which was found to be approximately 6 years. However, given a 20 year life the internal rate of return shows a return on investment of 14.88%. This result shows the profitability of the facility even in the worst scenario and case. The best scenario and case are with the cost and mean plus one standard deviation switch value. This scenario produced a 3.8-year SPP and a 26.05% IRR that is a large return on investment.

When adding the ethanol tax credit as a revenue steam the economics of the facility improve. The same scenarios are the best and worst, however the return on investment increases by over 30%, with the worst case SPP and IRR improving to 4.86 years and 20% respectively and the best case SPP and IRR improving to 2.9 years and 35% respectively. This large increase would either allow a lower hydrogen price to the consumer, or push for investment in P2G to initiate a hydrogen economy.

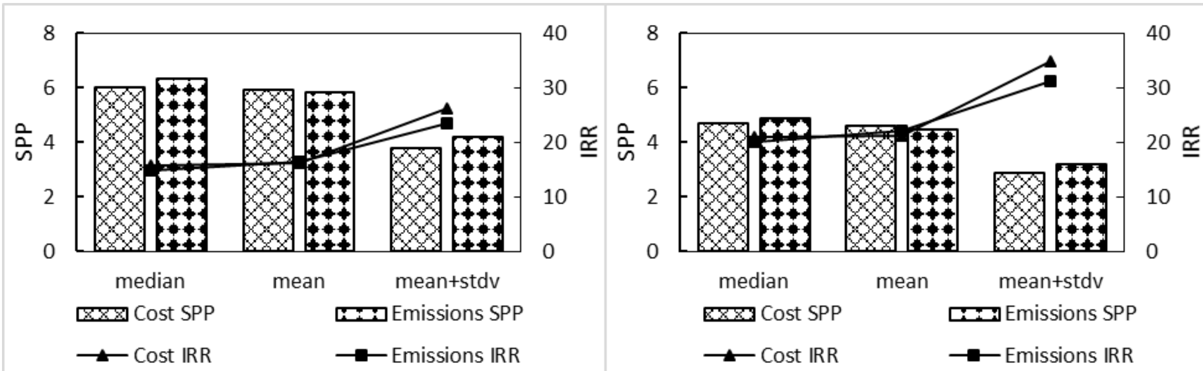

Figure 23: Simple Payback Period and Internal Rate of Return for both cost and emission scenarios using median, mean, and mean plus one standard deviation cases

Both the median and the mean show similar financial results with the mean plus one standard deviation showing the economic potential. Upon further analysis, it is shown that the increase in economic potential is largely due to more hydrogen being produced. The capacity factor for the facility changes relatively little between the median and the mean around 50%. When using the mean plus one standard deviation the capacity factor increases to operate a larger percentage of the time, 96% for the cost scenario and 82% for the emission scenario. This further supports the finding of previous works, which showed that the facility can operate at higher capacity factors and therefore can provide addition auxiliary services and further aid the jurisdiction [19].

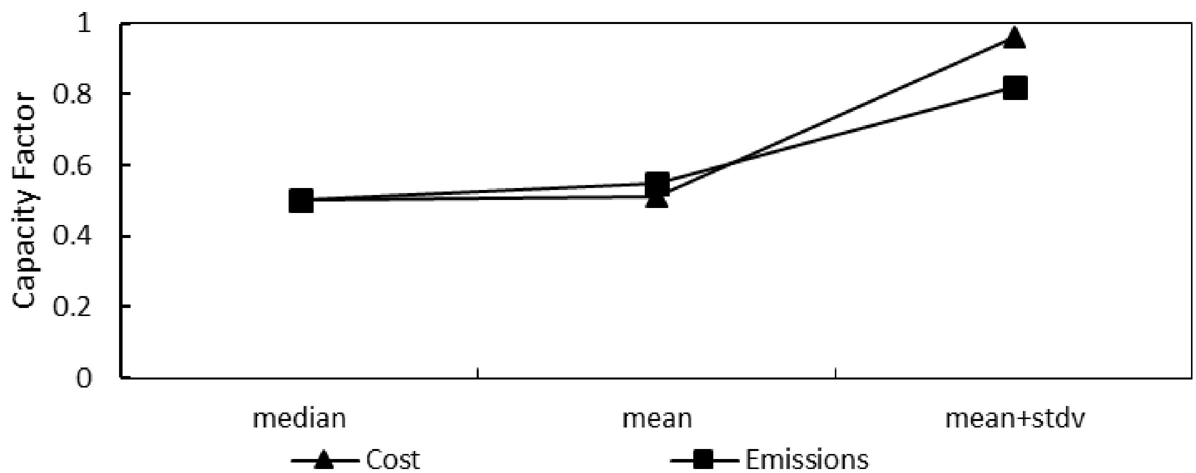

Figure 24: Capacity factor for both cost and emissions scenarios using the median, mean, and mean plus one standard deviation cases

4.2.3 Well-to-Wheel Emissions Reductions

To examine the overall emissions reductions on the transportation fuel in comparison to gasoline, it is necessary to examine both the material extraction phase, or "well-to-pump", and the drive phase, or "pump-to-wheels". With these two important steps included, it is possible to compare the emissions of the different fuel types. In this analysis, E5 and E10 gasoline is compared to hydrogen for a hydrogen fuel cell vehicle (HFCV) and a dual-fuel hydrogen/diesel vehicle.

A number of the previous lifecycle emissions for each of these types of fuels are available and have been examined in this paper. In previous sections, the total lifecycle emissions for ethanol and gasoline are outlined. Additionally, the burn characteristics of dual-fuel hydrogen/diesel engines is also examined in the methodology section of this text. Further, the "pump-to-wheels" emissions for hydrogen vehicles are known to be zero due to the behaviour of fuel-cell vehicles. Examining the dual-fuel hydrogen/diesel co-combustion vehicles it is necessary to examine the well-to-pump emissions of both the hydrogen and diesel components. In Table 6, the emissions values of the well-to-pump production for hydrogen and diesel are given on a per MJ basis.

Table 19: Well-to-pump emissions for H_2 and diesel fuel

Fuel	gCO_2e per MJ Fuel
H_2 Emissions avg	21.94
H_2 Emissions mean	24.06
H_2 Emissions mean +1 st.dev.	35.39
H_2 Price switch	44.6 – 48.13
Diesel	17.095 [71]

The overall lifecycle emission of greenhouse gases, measured in kg of CO_2e, is given in Table 7 below. The fuel blends examined here are 100% diesel, 11% H_2 – diesel dual fuel, 30% H_2 – diesel dual fuel and pure H_2. All of the fuels that contain H_2 are examined at the highest and lowest emissions factors found for hydrogen production, 21.94 and 48.13 g CO_2e per MJ, respectively. Using the two hydrogen-diesel blends of 11%-H_2 and 30%-H_2 it is possible to compare the lifecycle reductions of using H_2 as a co-combustible in diesel engines. The pure hydrogen fuel, given in the last two rows, is expected to be used in a pure hydrogen fuel cell vehicle instead of the diesel engine used for the other fuels. This means that the energy efficiency, measured in MJ per km in this table, is different for the pure H_2 fuel. In addition, due to the zero-emission nature of HFCVs, the only greenhouse gas emissions for this fuel comes from the production of hydrogen itself.

Table 20: Total Lifecycle Emissions for Diesel, Hydrogen and Dual Fuel Blends

Fuel Blend	gCO_2e per MJ Fuel Produced	gCO_2e per MJ Fuel Consumed	gCO2e per MJ Fuel Total	MJ per km	Yearly Energy MJ for 25,000 annual km	Total Energy (8 years use)	Yearly Emissions (kg CO2e)	Lifecycle Fuel Emissions (kg CO2e)	% Reductions
Diesel	17.10	173.06	190.15	2.63	65,789	526,316	12,510	100,079	
11% H_2 (max emissions)	20.51	141.67	162.18	2.63	65,789	526,316	10,669	85,356	15%
11% H_2 (min emissions)	17.63	141.67	159.29	2.63	65,789	526,316	10,480	83,839	16%
30% H_2 (max emissions)	26.41	90.00	116.41	2.63	65,789	526,316	7,658	61,266	39%
30% H_2 (min emissions)	18.55	90.00	108.55	2.63	65,789	526,316	7,141	57,131	43%
H_2 (max emissions)	48.13	0.00	48.13	1.36	34,000	272,000	1,636	13,091	87%
H_2 (min emissions)	21.94	0.00	21.94	1.36	34,000	272,000	746	5,968	94%

Next, in order to compare the overall well-to-wheels emissions of each of the fuels and fuel blends, it is necessary to use a common point of comparison. Here it is assumed that each vehicle is used for 8 years of driving with an annual use of 25,000 km. Under this assumption, one can now examine the emission reductions between diesel, the diesel-hydrogen blends and pure hydrogen blends. When 11% H_2 is used, the reduction in greenhouse gas emissions is 15-16% depending on whether the minimum or maximum emissions factor for the production of H_2 is used. As can be seen in Table 7, the lifecycle emissions reduction for hydrogen-diesel blends comes not from the fuel production, but the fuel consumption phase. This can also be seen in the 11% H_2 blend where the emissions reduction ranges between 39% and 43% for the maximum and minimum emissions factors for hydrogen production. The use of H_2 in the HFCV achieves a great magnitude of emissions reductions from its use phase due to its more efficient engine and the lack of use-phase emissions. Comparing the results in Table 7 to the questionable data for ethanol-gasoline blends in Table 3 illustrates the advantage of using hydrogen to provide fuel-cycle emissions reductions.

4.3 Conclusions

Moving forward, providing emissions reductions in the transportation sector remains an important technological goal of automotive manufacturers and industrial societies. With a target of only a 2-degree global temperature increase jurisdictions will have to find innovative ways to allow the integration of cleaner intermittent energy and more sustainable transportation fuels. The use of electrolytic hydrogen offers an excellent bridge from the current combustion-based transportation technologies to a future centered on hydrogen fuel cell vehicles and electric vehicles. To move towards these eventual technologies, hydrogen can provide significant emissions reductions in dual-fuel applications with diesel. When an 11%-H_2, 89%-diesel mixture is used greenhouse gas emissions are reduced 15%-16%; while a 30%-H_2, 70%-diesel mixture provided a reduction of 39%-43% in comparison to diesel. Thus, the use of blended H_2-diesel fuels provides significant emissions savings when contrasted with the ethanol blending that is mandated under the Renewable Fuel Standard. Given these reductions, and the incentives being offered to significantly less effective renewable fuels, like ethanol, it makes sense for policymakers to provide tools that encourage the production and use of electrolytic H_2.

Chapter 5: SUMMARY AND CONCLUSIONS

5.1 Summary of Conclusions

Government programs like the Feed-in-Tariff program are a disincentive to energy storage and have created instability in the market pricing

Energy storage is important for expanding the use of intermittent renewable energy. Policy has been put in place to increase renewable energy implementation, however it has been correlated with market price instability and an increase in adjustment pricing. The policy has also been shown to be a deterrent to energy storage by making it less profitable store and use energy smartly compared to selling it at the inflated Feed-In-Tariff price. This can be seen in the roughly $4,000 gain in profit under a market price contrasted with a roughly $4,000 loss under the current FIT program. This promotes a policy that does have benefits as renewable power generation has increased, however, it also promotes a policy that is unsustainable and has passed on significant cost to the consumer. An energy storage program should replace the Feed-In-Tariff program in order to promote renewables in a more sustainable policy.

Energy storage can be economically feasible if given preferential pricing such as energy exporters

Energy exporters get contracted pricing that does not include the global adjustment. These exporters benefit at times from the instability in the market when the market price of electricity is negative. To keep profits within the jurisdiction, energy storage should be priced similarly to energy exporters and not pay the global adjustment. This would ensure Power-to-gas makes economic sense and promote its wide spread use. This would help stabilize electricity pricing and reduce the frequency the price becomes negative due to a surplus of generation. By utilizing this pricing structure the Internal Rate of Return varies between 15 and 21 percent. This demonstrates the profitability of a Power-to-gas system.

Power-to-gas offers flexibility and provides benefits to multiple sectors

Not only can Power-to-gas be profitable but the benefits extend beyond the power grid. While stabilizing the power grid the hydrogen product can be used in a plethora of applications. In the near future or for heavy duty vehicles, dual fuel vehicles can be used which show anywhere between a 15% and 43% lifecycle emission reduction depending on the percentage of hydrogen used. The hydrogen can also be used for a fuel cell vehicle for which lifecycle emissions can be reduced by up to 94%. This therefore can decrease the emissions from the power grid through expanding the use of renewables or near zero emission power generation while also reducing emissions from the transportation sector.

By having the potential to be utilized in both combustion engines and a fuel cell vehicle, Power-to-gas can act as a bridge between current and future markets. This can be achieved by creating small systems that provide the hydrogen for dual fuel, which can be expanded when the demand exists due to the prevalence of fuel cell vehicles. This transition not only allows for refinement of the systems and controls to stabilize electricity but also answers the infrastructure questions about alternative energy vehicles.

5.2 Concluding Policy Remarks

Creating a sustainable future is an important project for both government and industry. The policies that are created must be sound environmentally but also sustainable economically. The policies must be sustainable economically to both achieve political will but also to maintain consumer acceptance of the technologies. To ensure the policies are environmentally sound a big picture approach will enable a program to benefit multiple sectors, from commercial to transportation. These policies, by taking an integrated approach, will benefit the province in the long term providing a clean, efficient, and effective energy future.

The following policy recommendations based on the conclusions offer sustainable solutions to Ontario's electricity storage problems:

- End the Feed-in Tariff program and replace it with a program that is not a disincentives to energy storage
- Allow Power-to-gas systems to be installed and price the electricity consumption at the market Hourly Ontario Electricity Price without the Global Adjustment
- Apply an equivalent ethanol tax credit to hydrogen produced by electrolysis of 79.5 cents per kilogram

5.3 Recommendations

5.3.1 Recommendations with respect to works

As demonstrated in this cumulated work energy storage systems are capable of being implemented in various fashions to meet specific needs. To meet the scale of the problem of mass electricity exports and negative market prices the scale of the energy storage must match. The focus on grid energy and transportation energy at a grid scale, provides the appropriate scale but also emissions reduction potential to combat global climate change.

To make Power-to-gas systems feasible there should be preferential pricing as both the implementation of the system and post production use of hydrogen offer substantial reduction of emissions for the jurisdiction. Be it a city, province, state or nation, the implementation of energy storage such as Power-to-gas should be part of a larger strategy to meet emission reduction targets. The energy storage providers should therefore be treated the same as an exporter and not have to pay the global adjustment fee as long as they help regulate the market price. By stabilizing the electricity prices and providing load shifting services more intermittent renewable energy can be implemented furthering the benefits.

5.3.2 Recommendations for future analysis

For future works a more integrated and detailed analysis should be conducted to more accurately predict the costs of the systems. These higher fidelity models will be able to prove beyond a reasonable doubt the profitability of these systems, making the economic case for clean energy and energy storage.

New policies and programs should be researched to determine the most sustainable solution that balances the environment and the economy. These programs could be new preferential pricing, or other market mechanisms that show the profitability of Power-to-gas in addition to the large environmental impact.

Power-to-gas utilizes sound technology and can be implemented in the current market. The impact of Power-to-gas on the environment, electricity pricing, and transportation energy and emissions has been discussed individually but not in an integrated strategy. By creating an integrated strategy, the case for Power-to-gas over other storage will be made and the integration of Power-to-gas into the power grid will be demonstrated.

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