Analysis of the Economic and Carbon Emission Reduction Potential of Fuel Cell Electric Vehicle-to-Grid in Alberta and Ontario

by
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AUTHOR's DECLARATION

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners. I understand that my thesis may be made electronically available to the public.

Abstract

Connecting battery electric vehicle (BEV) to the grid is a way of utilizing existing BEV fleet to cut the cost on energy storage and provide monetary incentives to vehicle owners. By coordinating the charging and discharging of the growing BEV fleet, the grid load can be shifted. Meanwhile, fuel cell electric vehicles (FCEVs) are gaining popularity, especially in heavy-duty vehicle market because of the advantages of hydrogen over battery such as the higher gravimetric density and faster refueling time. Similarly, FCEV fleet can also be connected with the grid (FCEV2G) and become moving energy generators that generate electricity and supply it to the grid using hydrogen. The hydrogen used can be produced locally with cheap and excess electricity or in a centralized production site at lower cost. A profit could be made to benefit from the high electricity price during peak hours, which can be shared among FCEV owners and the FCEV2G coordinator.

This study analyzes an FCEV2G station that can connect a few FCEVs to the grid to generate electricity. The operation, including local hydrogen production and storage, hydrogen purchased from a centralized plant, and schedules of FCEV2G, is modeled as a mixed integer linear programming problem. Using historical data of electricity price and generation mix in Alberta and Ontario, in 2019 and 2022, The profits of this FCEV2G station with different configurations are optimized and compared. Parameters including component efficiency, onsite electrolyzer are studied to investigate their impacts on the optimization result. The carbon emission potential of FCEV2G is also evaluated.

The results in Alberta show that an annual net revenue as high as 66k USD could be made in 2022 via FCEV2G, as the high and volatile electricity prices amplify the load-balancing function of FCEV2G. In addition, 185 t CO_2 emission could also be avoided by using clean hydrogen to generate electricity and supply it to the carbon-intensive grid in Alberta. However, under the base case assumption, such a FCEV2G station could not make profit in 2019 in Alberta because of the efficiency losses of the electrolyzer and fuel cells as well as the relatively stable electricity price. This means, high and unstable electricity prices through a year are the key factors for FCEV2G to be profitable.

On the other hand, Ontario has abundant nuclear and hydro power supply and hence maintain a stable electricity price profile. A parametric study is conducted to study how the profitability will depend on technological improvements in the future, and it finds that, by using the 2022 data, the FCEV2G station becomes profitable after market hydrogen cost divided by fuel cell efficiency is below 86 USD/MWh. Meanwhile, the carbon intensity of electricity varies largely in Ontario because natural gas is primarily used to meet peak demands. This allows a FCEV2G pathway to reduce the carbon emissions during peak hours, and the result shows as high as 213 t CO_2 emissions could be reduced in the 2022 base case.

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Table of Contents

List of Figures

List of Tables

Chapter 1. Background and Literature Review

1.1. Grid and Grid Balancing

1.1.1. Power Grid

Modern industry and civil life heavily depend on the fast and long-distance energy supply facilitated by power grids. An electric grid is a delivery network of electricity that connects suppliers with consumers. Mostly, a power grid is unidirectional and consists of three different components: generation, transmission, and distribution. Electricity is created in generation plants by using the energy of fossil fuels (such as coal and gas) or renewable sources (such as water streams and solar radiation). The generation sites are often far away from the population because of their potential hindrance to urban expansion, the pollution of fossil fuel power plants, and the location requirement of offshore wind turbines, etc. Therefore, once generated, electricity is carried over long distances by transmission lines, during which the electric voltage is elevated to reduce the energy loss along the transmission. Once reaching local communities, electricity enters individual households and businesses through distribution lines. Finally, electricity ends its journey in different appliances where it is converted into other types of energy such as mechanical energy and heat, fueling the functioning of our modern world.

Grid electricity is generated from different types of power plants, and they have different characteristics of supply stability. Nuclear, hydro, and coal-fired power plants generally provide a steady output which cannot be easily adjusted rapidly, so they usually comprise the base load of the grid. Natural gas-fired power plants, on the other hand, can be quickly regulated and are used to meet sudden consumer demand peaks, so it usually makes up the peak load. [1] Unlike fossil fuel power plants, the output of solar and wind is dependent on weather conditions including wind speed and solar radiation level. Although these renewable energy sources are essential to decarbonize the grid, the intermittent nature of their output poses a challenge to maintaining grid stability. As a result, natural gas-fired plants are frequently used in the integration of renewable energy into the grid because the output controllability of the former can compensate for the unpredictability of the latter and thus a stable total supply is maintained.

Demand is the power consumption on the end-user side, which is fluctuating but has a general daily pattern. Higher demand causes higher electricity prices and vice versa. Demand is usually the lowest from midnight to dawn where social activities mostly become dormant, and highest around early evening when the demand for lighting, heating, and cooling surges. Additionally, to accommodate the demand profile, the supply must be adjusted accordingly. The high demand for power during peak hours is met by more fossil fuel power plants than the demand during off-peak hours, because the power output of natural gas-fired plants is easier to control than other types of power generation. Consequently, the higher amount of gas consumption makes the electricity supply during peak hours more carbon-intensive. In summary, the daily pattern of power demand and characteristics of different power generations make the peak electricity more expensive and carbon-intensive, and end-users compete for the expensive and carbon-intensive electricity during peak hours but waste cheaper and cleaner electricity during off-peak hours.

With the ever-evolving economy and its need for electricity, the grid needs to evolve accordingly at the same time. There will be several important changes to the grid in the future. One is the expansion of solar and wind power generation. Renewable power generation is essential to cut carbon emissions and air pollution as well as meet mounting electricity demand. However, the increasing integration of them into the grid amplifies the impact of their intermittent output on grid stability. Another major issue is the rapidly expanding electric vehicle (EV) fleet, projected to account for 10% of road vehicles in 2030 [2], which is considered an important approach to decarbonizing the transportation sector. Unlike fueling conventional vehicles with oil or gas in fueling stations, EVs require electrical charging and drawing electricity from the grid. This large amount of EVs will significantly increase the demand for grid electricity. Furthermore, the EV charging schedule and location are up to individuals thus quite unpredictable. Climate change is also causing new issues like the increasing frequency of extreme weather events and consequently the increasing demand for heating and cooling. Next, the new concept of prosumers, which means electricity consumers can also become electricity producers by connecting small solar panels and wind turbines with the grid, increases renewable energy penetration into the grid but also increases the amount and unpredictability of distributed small-scale power generation which affects the stability of power grids. The functioning of grids relies on the matching of electricity supply and demand [3], but the increase of intermittent power supply and the fast growth of energy demand pose new challenges to balancing these two. Because of these future changes, measures should be taken to accustom grids to these new trends of shifting electricity supply and demand.

1.1.2. Grid Stability and Smart Grid

Grid stability is the ability of a grid to regain its steady-state operating condition after a disturbance. [4] Stable voltage and frequency of grid electricity are vital to the operation of factories and appliances relying on grid electricity. Maintaining grid stability is necessary but very costly: quick response electric services, responsible for balancing the electricity supply and demand, cost 12 billion USD per year in the US, accounting for 5%-10% of the total electricity cost. [5] Due to the future changes to grid supply and demand as discussed in Section 1.1.1, this cost will become higher. Therefore, new approaches should be developed to help maintain grid stability.

To maintain grid stability, it is crucial to adjust the electricity demand and supply according to the other. Because of the increasing uncertainty on both sides of the grid, stability maintenance needs rapid communications between both sides so that the demand and supply can be adjusted according to the other. However, conventional grids are unidirectional where no information exchange is allowed. A smart grid, on the contrary, is contrived to allow the consumers and producers to communicate and accordingly adjust the input and output of the grid, improving the grid stability.

Smart grids are necessary for integrating distributed power generation into the power grid such as solar panels and wind turbines. Unlike conventional coal, gas, and hydro power plants that are usually large and centralized, wind and solar power plants are usually distributed because of their low energy intensity per land area and their location requirement. The large number of these emerging small power plants with unstable outputs requires swift information exchange for power output regulation, demand response, and grid stability maintenance. A smart grid allows renewable energy resources to be safely plugged into the grid to supplement the power supply with power from the generation and storage of prosumers. [6]

There is not a universally accepted definition of what a smart grid is, but the definitions have common grounds. According to the Strategic Deployment Document for Europe's Electricity Networks of the Future [6], a smart grid should intelligently connect the producers and consumers to keep electricity supplies sustainable, economic, and secure. As for the National Institute of Standards and Technology [7], a smart grid should combine various digital computing and communication services into the power system, and its bidirectional energy flows, communication, and control capabilities can bring in new functionalities.

1.1.3. Vehicle-to-Grid

Although the increasingly popular EVs will certainly change the electricity demand profile and thus affect the grid stability, these automobiles can also become moving energy storage helping manage the grid load. The bidirectional integration of EVs and grids is referred to as vehicle-to-grid (V2G). [8] V2G allows personal automobiles to have the opportunity to become not only vehicles, but mobile and self-contained resources that can manage power flow and displace the need for electric utility infrastructure. They act as vehicles when drivers need them and become power sources or energy storage during peak hours, recharging at off-peak hours. The charging and discharging of EV batteries can assist in load balancing and increase the load forecast accuracy. By meeting the peak electricity demand with the energy stored during off-peak time, V2G can enable vehicles to simultaneously improve the efficiency and profitability of electric grids, reduce greenhouse gas emissions, accommodate low-carbon sources of energy, and reap cost savings for owners, drivers, and other users. In addition, the energy stored in EV batteries can act as backup power in case of supply shortage. Furthermore, the time and locations of EV charging and discharging can also be designed to improve the utilization of available generator capacity and distribution infrastructure.

If the value of V2G can be used to facilitate the EV share in the automobile market, carbon emissions can be further reduced. In summary, V2G can benefit EV owners, grid operators, electricity ratepayers and society generally.

V2G has many advantages over other grid-scale energy storage approaches. A study predicted and compared the future development of several grid-scale energy storage methods, including compressed air, pumped hydro, batteries, and V2G. It concluded that V2G will have the largest energy storage potential because of the rapid growth of the EV fleet, and it has the lowest installation cost due to the lowest amount of new site construction. [9] Another study evaluated the revenue and cost of V2G providing peak load and estimated the annual net revenue is 290 USD for one vehicle. [5] The EVs needed by V2G will be abundant in the future: Transportation Research Board reported that V2G can utilize 50 million vehicles worldwide. [10] In summary, V2G is predicted to play a vital role in the future grid operation.

Due to the benefits of V2G, there have been 130 V2G projects with more than 6800 chargers in 27 countries so far, according to V2G Hub. [11] Despite its benefits, it is still at the early stage of pilot projects. Among the first ones, University of Delaware connected 23 personal vehicles of different models to the grid to offer frequency regulation in 2009. [12] Another project was in Japan, in 2013, where Nissan carried out a successful field test where up to six Nissan LEAFs were connected to a building and provided it with power during peak hours, and the cars were fully charged at the end of the workday. In this case, the V2G reduced 2.5% of peak electricity use of the tested facility and saved 500,000 JPY (approximately 4,000 USD) annually. The company expected the technology to enable companies to regulate their electricity bills with their employees' cars. [13] In 2021, EV Connect partnered with Indiana's Battery Innovation Center and Energy System Network to create a large-scale V2G-using school buses and heavy-duty trucks. This project aims to obtain rich data on battery life, available cycle numbers, and actual discharge rates to investigate the impacts of V2G on commercial vehicle batteries. [14] In 2022, SWTCH launched a two-year V2G pilot project in Toronto using a Nissan LEAF and a new multi-unit residential building to monitor the performance and collect data for designing wider-scale applications in the future. [15] A very recent large-scale V2G demonstration in 2023 was based in Nottingham Britain, where 40 V2G chargers were combined with 138 kWp solar arrays and batteries recovered from discarded EVs. [16] These V2G projects and demonstrations show the growing prospect of V2G, but the future potential expansion and large-scale adoption rely on the outcomes of these ongoing pilot V2G projects.

1.1.4. Fuel-Cell-Electric-Vehicle-to-Grid

Commercially available fuel cell electric vehicles (FCEVs) use proton exchange membrane fuel cells (PEMFCs) to convert hydrogen into electricity and have a high-voltage battery connected in parallel. The battery is used for regenerative braking and provides additional power for acceleration. This combination of fuel cell (FC) and high-voltage battery is capable of delivering almost every kind of electrical energy service, from balancing to emergency power back-up, primary reserve or reconverting hydrogen from seasonal hydrogen energy storage in underground salt caverns. [17] Hundreds of grid-connected FCEVs sitting in parking lots could function as local power plants and balance entire cities and countries, resulting in cost-effective balancing power for intermittent power sources.[18]

Several studies have attempted to analyze the technical and economic feasibility of FCEV-to-grid (FCEV2G). One study installed an external alternating current (AC) grid connection on a commercial FCEV and experimentally verified that parked FCEVs can act as virtual power plants. [19] Another study proposed a single-switch high-voltage direct current (DC)-DC converter to integrate the lower-voltage fuel cell energy units into the higher-voltage grid. In the simulation, they successfully used an FCEV to fulfill the energy need of a household load and supply the excess electricity into the grid. They also found that daily operation can considerably lower the cost of purchasing grid electricity. [20] In another study, an economical optimization model is proposed, which considers FCEV2G integrated green buildings with vehicle visiting time data simulated from the Monte Carlo method and confirms the economic potential of FCEV2G. [21] Moreover, some other studies suggest that a small-scale FCEV2G can significantly boost the autonomy of microgrids, and a large-scale FCEV2G can potentially balance grid electricity supply and demand. [18], [22] In summary, there is abundant evidence demonstrating the validity of the concept of FCEV2G. However, more studies should be conducted on the feasibility and profitability of implementing FCEV2G in different economic and geographic contexts.

1.2. Hydrogen

1.2.1. Advantages of Hydrogen as an Energy Carrier

The decarbonization of the transportation sector requires replacement of diesel with clean energy such as low-carbon electricity and hydrogen, while hydrogen has certain advantages over electricity. Taking rail transportation as an example, although electric trains with overhead wires are emission-free during operation and more technologically mature compared to hydrogen fuel cell electric trains, they have certain inherent drawbacks. For example, they require significant investments in the construction and maintenance of the electric wires and substations, because continuous electricity influx from the overhead catenary systems during their operation is needed. This expenditure can be even higher in remote or mountainous regions, where the construction and maintenance of infrastructure are more difficult than in urban regions. [23] Even though battery-electric trains are proposed as an alternative to reduce the use of overhead catenary systems, the fast-charging infrastructure for battery electric trains is expensive while the battery swapping method substantially reduces the battery utilization rate. [24], [25], [26] Also for heavy-duty trucks and airplanes, their high power demand asks for a large amount of onboard energy storage, and using batteries adds too much weight on them where additional weight seriously affects the performance. Overall, although using electricity via wires and batteries is an important means to decarbonize vehicles, it is difficult to use it in every scenario. [27]

On the other hand, hydrogen fuel vehicles are also clean during operation. Compared to electric trains, hydrogen fuel cell electric trains require little wayside infrastructure, and thus can potentially reduce the cost of rail decarbonization. [28] Hydrogen is a chemical fuel that can be oxidized to release a large amount of energy and produce water as the only product; its gravimetric energy content is 2.8 times that of gasoline. [29] Hydrogen can be used to power vehicles via two means: combustion in engines that directly pass mechanical energy to onboard machinery [30], or oxidation in FCs that convert chemical energy directly to electricity to power electric motors [31]. Hydrogen-powered trains generate zero carbon emissions or air pollution during their operation, and they may have low life cycle emissions if the hydrogen fuel is produced from clean energy such as heat or electricity from nuclear, solar, or wind power plants. Hydrogen-powered trains require less initial investment compared to electric trains with overhead catenary systems [32] and hydrogen vehicles have shorter refueling time compared to battery vehicles [24]. Therefore, they can be a promising approach to decarbonizing transportation.

However, several challenges need to be overcome to accelerate the adoption of hydrogen fuel in rail transport. First, although many studies suggest hydrogen storage and usage are safe, a large part of the public is still concerned with its safety. [33] Second, effective onboard hydrogen storage has difficulties because hydrogen gas has very low volumetric density compared to conventional fuel, as shown in Table 1-1 and must be compressed to above 350 bar, or liquified at -253 °C for onboard fuel storage. The high pressure or low-temperature conditions lead to high expenditure on storage vessels and increased energy consumption for compression or refrigeration. [34], [35] Therefore, it is critical to reduce the capital, maintenance, and operation cost of using hydrogen fuel and facilitate its adoption for rail transport.[36]

Table 1-1 Volumetric Energy Density of Different Fuels based on their Lower Heating Values

Name	Lower Heating Value [MJ/L]
Diesel	36 [37]
Gasoline	32 [37]
Hydrogen (ambient condition)	0.011 [38]
Hydrogen (compressed, 700 bar)	5.0 [39]
Hydrogen (liquid, -253 °C)	8.5 [39]

1.2.2. Hydrogen Production

Hydrogen is clean and non-toxic in terms of its use because water is the only product, albeit hydrogen production end is not always environmentally friendly. Hydrogen can be produced from a variety of sources including fossil fuels and renewables, and the methods determine the energy efficiency of the hydrogen production and carbon intensity of the produced hydrogen. According to its production approach, hydrogen is labeled in different colors, such as green, grey, blue, turquoise, etc. Green hydrogen has the lowest carbon intensity and thus the most desirable for establishing a clean economy, but it is much more expensive than hydrogen produced from fossil fuels, which explains why the global demand for hydrogen is primarily met by hydrogen from fossil fuels [40], as shown in Figure 1-1. This section summarizes the characteristics of different hydrogen production approaches, which generate different levels of carbon emissions and consequently assigned with different colors as shown in Table 1-2.

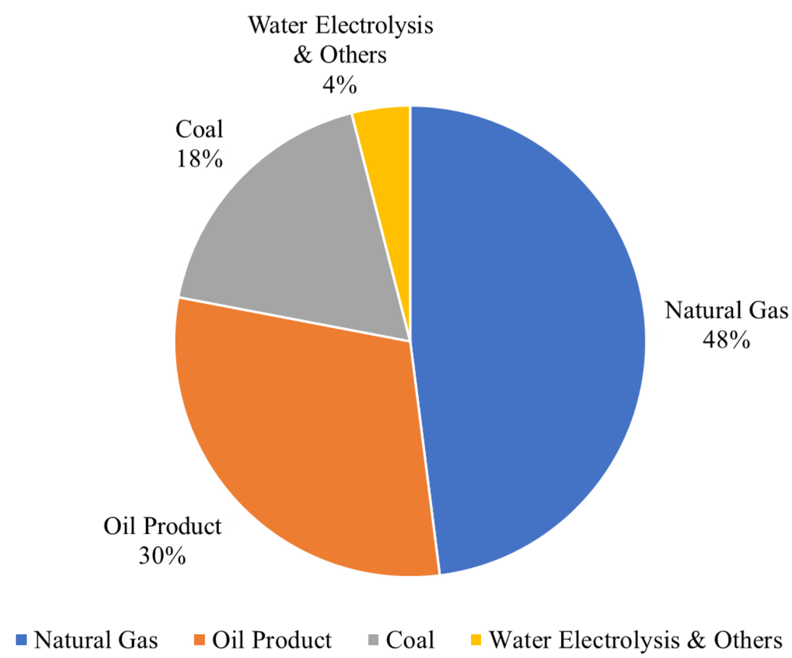

Figure 1-1 Percentage of Hydrogen Production from Different Sources [41]

Table 1-2 Energy Source and Production Method of Hydrogen of Different Colors [42]

Energy Source	Hydrogen Production Method	Carbon Intensity (CO_2eq/kgH_2)	Color
Renewable Energy	Electrolysis	0.7 – 2.8	Green
Natural Gas	Steam Reformation	8 - 13	Grey
Natural Gas	Steam Reformation with Carbon Capture and Sequestration	1 - 5	Blue
Natural Gas	Pyrolysis	2 - 5	Turquoise
Brown Coal	Gasification	18 - 25	Brown
Black Coal	Gasification	18 - 25	Black
Nuclear	Electrolysis	0.3 – 0.6	Pink

Steam methane reforming (SMR) is the most popular way of hydrogen production at the present, and almost half of the world's hydrogen is derived from this source, as shown in Figure 1-1 [41]. SMR includes three steps and generally happens at high temperatures around 800 °C with catalysts made of precious metals or nickel-based materials [43]. First, methane and water vapor are combined in a reforming reactor to obtain syngas, a mixture of primarily H_2 and CO. Then, the CO is converted to CO_2 in the water gas shift (WGS) reaction. Finally, the hydrogen is purified from the gas mixture. [41] A large amount of carbon is released in this process, and its treatment decides the color of the hydrogen product. If the carbon is emitted to the atmosphere, the hydrogen is regarded grey, meaning this hydrogen causes large amount of carbon emissions; if the carbon is captured and sequestrated, then the hydrogen is labeled blue, indicating the carbon emissions of producing this hydrogen is significantly reduced.

Apart from SMR, there is another hydrogen production method using methane without producing carbon in gases such as CO and CO_2. Methane pyrolysis, conducted at high temperatures between 900-1900 ºC, transforms methane into hydrogen and carbon black through several steps of decomposition [44]. This method has no carbon emissions into the atmosphere and the side product carbon black can be easily transported and stored, at the expense of higher reaction temperatures. The hydrogen produced from this method is labeled turquoise.

Hydrogen can also be produced from oil products via partial oxidation, where oxygen below the stoichiometric threshold for complete oxidation at a temperature of 1200-1350 ºC [45], and the hydrocarbons in the oil products are cracked into hydrogen and carbon monoxide. Meanwhile, another fossil fuel source, coal is also used for hydrogen production. Similar to hydrogen production based on methane and oil products, coal can be grounded and combined with water vapor and oxygen to produce hydrogen. Coal is the most abundant fossil fuel source, but this method is the most carbon-intensive one. [41] The hydrogen produced through coal gasification is labeled as brown or black, depending on which type of coal is used.

To meet the future demand for clean energy, hydrogen should be mass produced in a clean way of production in the future. Water electrolysis produces hydrogen only with water and electricity, and this method is clean as long as the electricity input is clean. In water electrolysis, water is driven by direct current to decompose into hydrogen and oxygen, which are produced at the cathode and anode, respectively. The two products can be easily separated because of their different generation locations and thus a high product purity can be easily obtained. Furthermore, no reliance on fossil fuels enables this method to be implemented in regions without natural fossil fuel resources.

A future green hydrogen mass production is envisioned to be water electrolysis coupled with wind and solar farms. Meanwhile, pink hydrogen, produced from waste heat of nuclear power plants also involves little carbon intensity. However, the total emissions and the carbon intensity of current hydrogen production remains high because the uptake of low-carbon and renewable hydrogen is advancing slowly. To reduce 10% of total emissions from hydrogen production by 2030, emissions intensity should be halved. [46] Renewable and low-carbon hydrogen is still more costly than hydrogen from fossil fuels, which can be attributed to the high cost and low availability of renewable electricity, as well as high electrolyzer CAPEX. However, electrolyzer CAPEX is projected to decline in the near future through design innovation and economic scale-up. [46]

1.2.3. Hydrogen Storage

There are several existing hydrogen storage methods, including compressed gas, cyro-compressed gas, liquid, physical absorbent, and metal hydrides. The density of hydrogen in different storage methods is shown in Table 1-3. All the currently commercialized hydrogen FCEVs adopt compression storage, as it is technologically more mature compared to other storage methods such as liquid hydrogen storage and metal hydrides. [47] However, compressed gas has a small gravimetric density and can only store limited amounts of hydrogen in a fixed volume. Liquid storage has a much higher volumetric storage capacity, but its drawbacks include the need for maintaining an extremely low temperature (e.g., -253°C) and hydrogen loss due to the boil-off phenomenon. [48] Yet for hydrogen vehicles, a high volumetric storage capacity is more appealing for a long-haul operation. For example, a hydrogen train project in South Korea was reported to use liquid hydrogen storage onboard. [49]

Table 1-3 Comparison of Hydrogen Volumetric Density of Different Storage Methods

Storage Method	Storage Condition	Volumetric Density [gH_2/L]
Hydrogen gas,	1 bar, 25 °C	0.0814[a]
Compressed hydrogen gas,	350 bar, 25 °C	24.5[b]
Compressed hydrogen gas,	700 bar, 25 °C	41.4[b]
Liquid Hydrogen	1 bar, -253 °C	70.8 [47]
Physical Adsorbent, Activated Carbon	30 to 60 bar, -196 °C	38.5 [47]
Metal Hydride, MgH_2	1 bar, 25 °C	106[c]
Metal Hydride, $FeTiH_2$	1 bar, 25 °C	106[c]
Ammonia	10 bar, 25 °C	107 [c]
Methylcyclohexane	1 bar, 20°C	47[c]
Methanol	1 bar, 25 °C	100[c]

a. Calculated from Ideal gas law.

b. Calculated from the standard form of Peng-Robinson Equation

c. Theoretically maximum, assuming all the hydrogen carriers being converted using the densities ([50], [51], [52], [53])

The location of onboard hydrogen storage is critical to improving safety. As for trains, there are currently two designs to situate hydrogen tanks on trains where hydrogen fuel can be easily separated from carriages in case of leakage. The first design is to place hydrogen tanks on the roofs of the carriages, which is adopted by the model Coradia iLint from Alstom. [54] Because hydrogen has a very small density, it easily dissipates and rarefies in the atmosphere in case of leakage and the risks of potential explosion are consequently reduced. [55] The other design is to have a carriage dedicated to hydrogen storage and FCs, which is adopted by the model FLIRT H_2 from Stadler. [56] This design separates the storage and power units from passengers or cargo, and hence, reduces the danger posed by the power/storage carriages to others in case of power/storage failure. This latter design also allows the refueling process to be done by swapping the power/storage carriages, which are refueled separately. As for trucks, Nikola Motor designs the hydrogen tanks to be placed in a vertical order behind the driver seat in their commercially available hydrogen truck model TRE FCEV, possibly also considering possible leakage. [57] However, likely owing to limited onboard space, the commercially available hydrogen vehicle model Mirai from TOYOTA locates the hydrogen tank beneath the vehicle. [58]

1.2.4. Hydrogen Refueling

Hydrogen refueling stations (HRSs) are an essential part of hydrogen infrastructure, and their expansion is a prerequisite to hydrogen penetration into the transport sector. Until the end of 2022, there were already

814 hydrogen refueling stations around the world, with 315 construction plans in place. [59] A hydrogen refueling station is more complex than a regular gas station serving liquid fuels such as gasoline and diesel. The uniquely needed components include high-pressure or cryogenic tanks, powerful compressors, and refrigeration units, which are essential to tackle the unique properties of hydrogen such as the extremely low volumetric density.

Two typical gas HRS layouts are shown in Figure 1-2. The hydrogen is stored in onsite storage tanks (50-200 bar, 25 °C), or directly supplied from hydrogen pipelines (20-50 bar, ambient temperature), onsite production devices (10-30 bar, ambient temperature), or tube-trailers (200-500 bar, ambient temperature). The hydrogen pressure needs to be elevated to match the onboard storage pressure during refueling(for example, 700 bar in this case). One approach is to compress the hydrogen to 900-950 bar and maintain the pressure in high-pressure buffer tanks, whose pressure difference with the onboard storage (700 bar) drives the hydrogen into the vehicle during refueling. Another approach is to first compress the hydrogen to 400-500 bar and use a booster compressor to raise the pressure to 900-950 bar during refueling. [60].

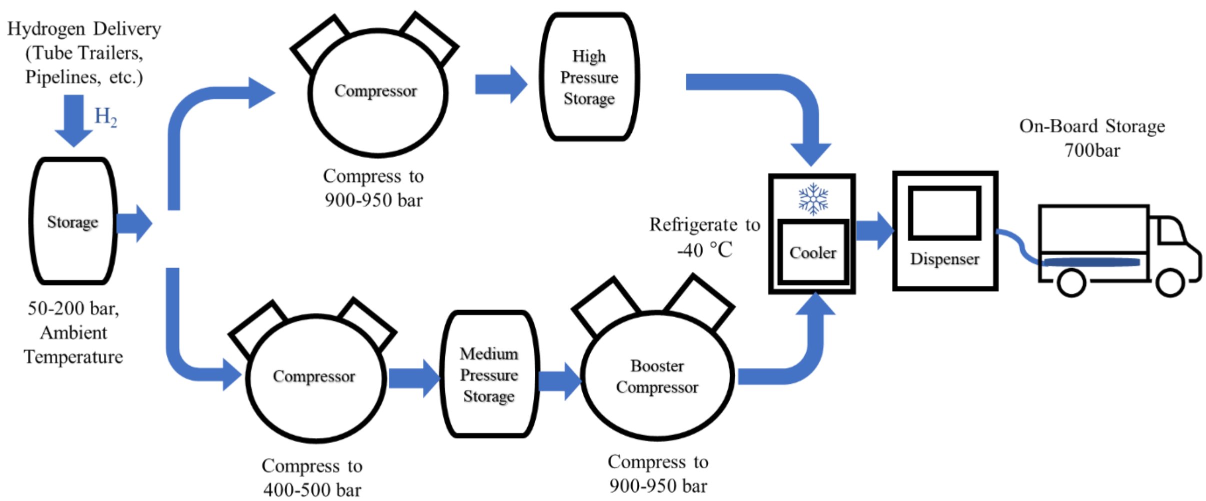

Figure 1-2 Typical Layouts of Gas Hydrogen Refueling Stations where Onboard Storage is 700 bar

Compressors are the component that dominates the capital and energy cost in HRSs. [61] Compressors used in HRSs can be categorized into mechanical compressors and non-mechanical compressors. [62] Mechanical compressors are currently more popular, and they can be generally classified into four categories: piston compressors, diaphragm compressors, linear compressors, and ionic liquid compressors, among which piston and diaphragm compressors are technologically mature and popular in HRS applications. [62], [63] There are also unconventional compressors that use thermal and chemical approaches instead of mechanical compression to raise hydrogen pressure. The working principles and efficiencies of the aforementioned types of hydrogen compressors are summarized in Table 1-4. More information regarding these compressors can be found in [62], [64].

Table 1-4 Working Principles and Efficiencies of Mechanical and Non-Mechanical Hydrogen Compressors

Type	Working Principle	Efficiency
Mechanical Compressors		
Piston Compressors	The reciprocating motion of pistons compresses gaseous hydrogen [65]	No Data
Diaphragm Compressors	They are similar to piston compressors, but hydrogen and piston are separated by a diaphragm and hydraulic fluid, which increases hydrogen purity. [62]	65% [66]
Linear Compressors	They are similar to piston compressors, but the piston is directly connected to a linear motor with a resonating spring. [67]	73% [68]
Ionic Compressors	They are similar to piston compressors, but molten salt at room temperature is used as a liquid piston. [69]	No Data
Non-Mechanical Compressors		
Cryogenic Pumps	Instead of compressing gaseous hydrogen, liquid hydrogen is pressurized under -253 °C. [70]	No Data
Metal Hydride Compressors	Because of the exothermic nature of hydrogen release and the endothermic nature of hydrogen absorption, hydrogen pressure can be controlled by manipulating the temperature of the metal hydride. [71]	3%-5% [71]
Electrochemical Compressors	Driven by external electric current, hydrogen travels in the form of protons across a proton exchange membrane where only protons are allowed to cross. [72]	80% [72]
Adsorption Compressors	Similar to metal hydride compressors, hydrogen pressure is controlled by the hydrogen release and adsorption of porous material, which is affected by its temperature. [73]	No Data

Beside hydrogen compressors, cascade storage systems are widely adopted as additional refueling devices to save energy. They substitute the high-pressure buffer tanks with usually three stages of pressure, the lowest 350-500 bar, medium 500-700 bar, and the highest above 900 bar. [74] Each of them is responsible for refueling when the onboard storage is at different pressure levels, which requires less compression power than solely using hydrogen above 900 bar to refuel the whole onboard storage. [75]

Another essential equipment is the refrigeration unit, which is required to pre-cool hydrogen fuel to sub-zero temperatures before dispensing it to vehicles. This is because the onboard hydrogen tank is sensitive to temperature increases caused by the fueling process: hydrogen expands when being dispensed into onboard storage and heats up as a result of its negative Joule-Thomson value. [76] For example, for a 700-bar hydrogen tank, the fuel should be precooled to -40 °C before being filled into the onboard storage to prevent overheating. [77] Because the heat generation during hydrogen filling must be offset, a more powerful pre-cooling system is necessary for higher refueling speed and a higher final state of charge. [78]

Dispensers are the last stage of hydrogen refueling and where customers directly interact with the refueling systems. They monitor and control the hydrogen flow into the vehicles. [60] Unlike conventional gasoline and diesel dispensers, hydrogen dispensers must be able to withstand the sub-zero temperatures and high pressure of the precooled hydrogen. The key components include high-pressure filling pipelines, gas guns, pneumatic shut-off valves, temperature and pressure sensors, etc. [63]

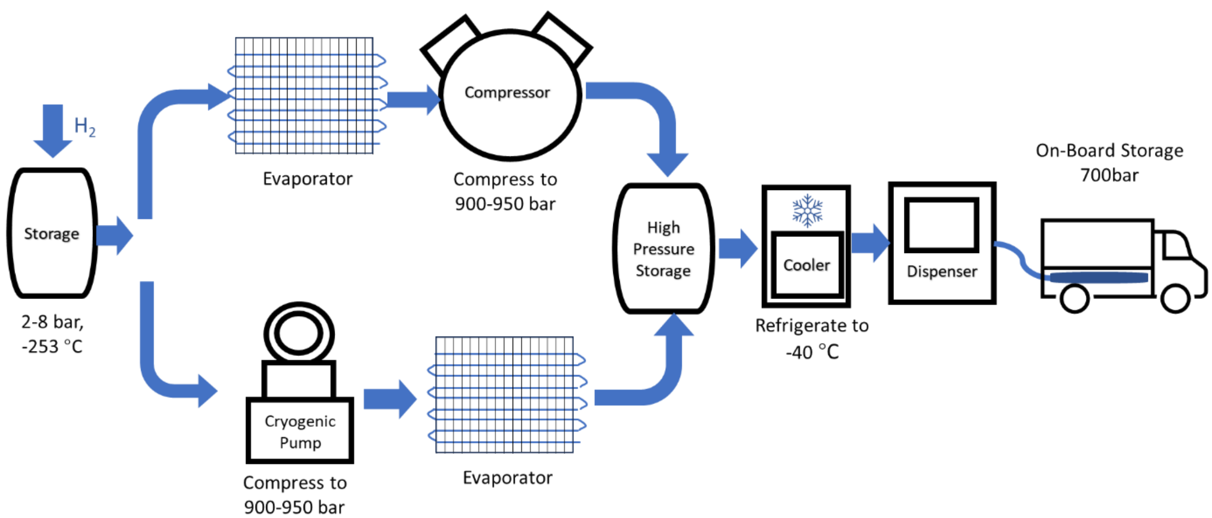

Figure 1-3 Typical Layouts of Liquid Hydrogen Refueling Stations where Onboard Storage is 700 bar

Two common pathways of refueling liquid hydrogen are shown in Figure 1-3. Liquid hydrogen is stored in cryogenic tanks which keep the hydrogen at -253 °C, 2 to 8 bar. To process the liquid hydrogen to 700 bar gaseous hydrogen for onboard storage, the liquid needs to be first evaporated to gas and then compressed to 900-950 bar, or alternatively first pressurized by a cryogenic pump to 900-950 bar and then evaporated to compressed gas. [60], [79] After the liquid hydrogen is converted to gaseous hydrogen at 900-950 bar, the refueling processes and equipment are the same as those in gas HRSs.

1.3. Social Acceptance of Renewable and Clean Energy

The implications of renewable and clean energy rely on the social acceptance of these new technologies. The establishment of renewable power plants brings clean electricity to local communities and contributes to the local economy, but in the meantime, some social backlash against this new development arises from concerns over these new changes to the local communities. For example, building large wind turbines and solar panels occupies land and may damage landscapes as well as endanger local vulnerable ecosystems. Recently, a renewed protest in Norway targeted at the 151 turbines of Europe's largest onshore wind farm, which is located in central Norway's Fosen district, about 450 kilometers (280 miles) north of Oslo. [80] Locals fear that the renewable energy transition is coming at the expense of indigenous people and their way of life because the construction affects the local reindeer grazing and herding. [81] In southern Italy, despite an overall positive consumer attitude toward local wind power development, which is one of the largest onshore wind generation projects in Europe, some local residents complain about the landscape damage and noise generation. [82]

In terms of increasing social acceptance toward wind turbine construction, it is suggested in one study [83] that improving the efficiency and aesthetics of wind turbines can enhance local touristic activities and regional economies. From a broader view, another study [84] suggests that specific supportive and restrictive policies, as well as the stability of these policies, have a positive influence on public confidence in the new renewable energy projects. It is also pointed out that a lack of knowledge in financial institutions is withholding the investment in renewable energy expansion. Governments should establish policies abolishing the financial barriers of expanding renewable energy development. These policies may include emission reduction targets and creating a connection between local and national energy policies. Social advances are as important as technological advancements in terms of promoting renewable energy.

1.3.1. Hydrogen Economy

The hydrogen economy refers to a system where hydrogen is used as an energy carrier to meet various energy needs including transportation, industry, and electricity generation. An ideal hydrogen economy will produce minimum carbon emissions in the lifetime of hydrogen, which requires hydrogen produced from green energy sources, hydrogen transportation infrastructures, and wide adoption of hydrogen vehicles and furnaces, etc. While the hydrogen economy is promising for reducing carbon emissions and facilitating renewable energy adoption, its emergence is dependent on increasing the cost-effectiveness of hydrogen production, hydrogen storage, and hydrogen infrastructure in the future.

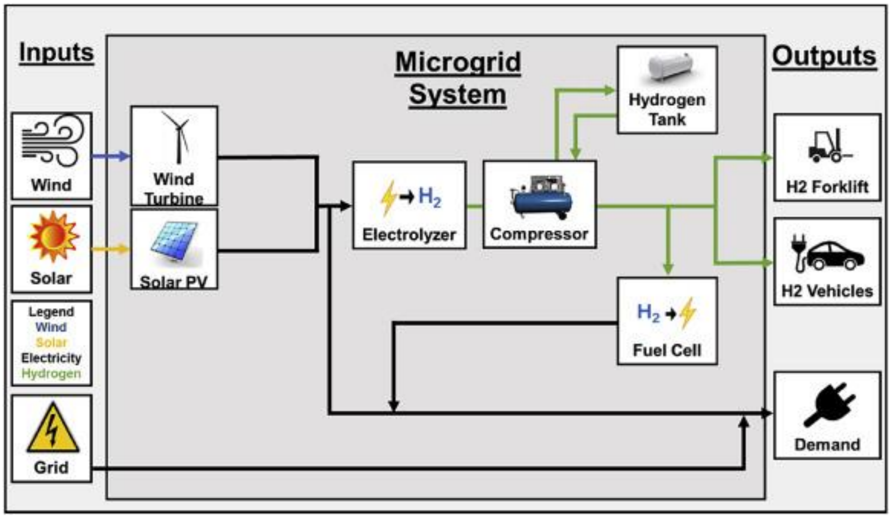

Figure 1-4 Schematic of Hydrogen as an Energy Vector in a Microgrid System (Reprinted from [85] with permission from Elsevier)

As shown in Figure 1-4, hydrogen can be used in different ways. Renewable energy production, such as wind turbines and solar panels, generates intermittent electricity output which cannot be totally supplied to the grid but can be used to produce hydrogen. The primary usage of this hydrogen will be industrial usage for a long time in the future as shown in Figure 1-5. However, some hydrogen can be used in transportation and power generation/buffering when the scale of hydrogen expands. As reported by hydrogen council [86], hydrogen will start to be used in these domains starting around 2030, which allows the emergence of FCEV2G in the hydrogen economy which combines hydrogen in transportation and power generation/buffering.

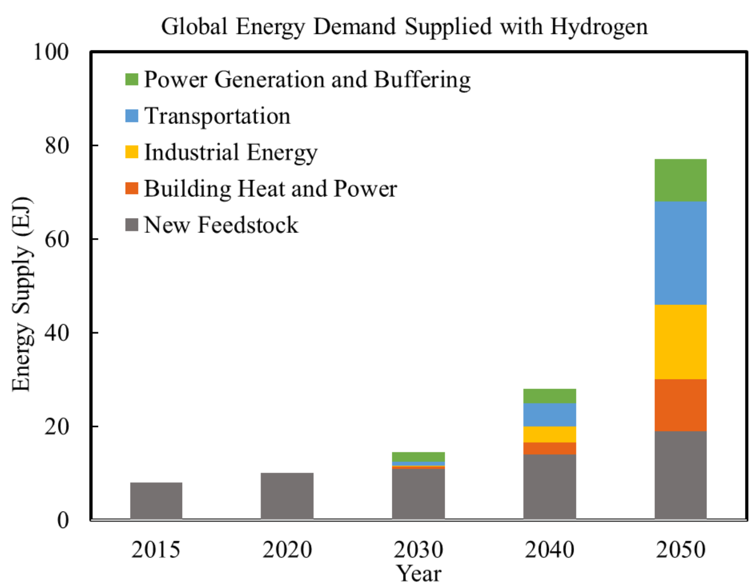

Figure 1-5 Global Energy Demand Supplied with Hydrogen in Different Years [86]

1.4. Hydrogen Strategies in Ontario and Alberta

Hydrogen is gaining interest of many governments around the world, including Alberta and Ontario which are ones of the largest economies in Canada. Alberta is the largest hydrogen producer in Canada. In 2022, Alberta produced about 2 million tons of unabated hydrogen and 0.5 million tons of methane-based hydrogen abated with carbon capture, utilization, and storage for diverse industrial applications. According to its hydrogen roadmap [87], the government of Alberta aims to integrate hydrogen into its domestic markets on a large scale and various projects are already underway, including Edmonton Region Hydrogen Hub, and a list of these hydrogen projects in Alberta can be found in [88]. Meanwhile, Ontario also has a hydrogen strategy [89], which identifies the advantages of developing a hydrogen economy in Ontario and lists the plans of encouraging hydrogen innovation. For this purpose, the government of Ontario launched a 15 million CAD fund for encouraging private enterprises entering hydrogen business and facilitating integration of hydrogen into the clean energy system. Although these two provinces have developed detailed plans and injected large funds into various hydrogen projects, the hydrogen infrastructure and hydrogen economy are still in its infancy in these two provinces. In terms of when they will have mature hydrogen economies, Alberta expects its hydrogen economy to begin boosting employment market and creating tens of thousands of jobs by 2030 [88], and this time is set to be by 2050 in Ontario [90].

1.5. Motivation and Outline

There are already some important research works regarding FECV2G. However, to the best knowledge of the author, there is no case study that considers a comprehensive planning of a large-scale FCEV2G, and the existing case studies rather consider FCs interacting with a small energy consumer such as a household. However, a large-scale FCEV2G is more feasible at fueling stations because FCEVs can use the abundant hydrogen reserves and the existing infrastructure in the stations to lower the cost of FCEV2G. Therefore, this study considers a large FCEV2G interaction with the grid and investigates its economic and environmental potential.

This study presents a mixed integer linear programming (MILP) model to maximize the gross economic profit and carbon emission reduction while subject to constraints such as the maximum power of electrolyzers and fuel cells. The historical data on electricity prices and carbon intensity in Alberta and Ontario in 2019 and 2022 were used. This model delivers the optimal energy storing/releasing schedule to obtain maximum profit or carbon reduction with a set of pre-defined parameters. The cost of the components used in the hypothesized FCEV2G site is estimated and combined with the cost of electricity and hydrogen to obtain the total cost. Then, a sensitivity analysis is performed to investigate the effects of different technological and social-economic parameters on the optimization result. In the end, some suggestions are given regarding future works.

Acknowledgement:

Parts of the contents in this chapter are in a manuscript that is under review:

D. Ding, X.Y. Wu, “Hydrogen fuel cell electric trains: technologies, current status, and future,” Applications in Energy and Combustion Science, under review, 2023

Chapter 2. Optimization Methodology and MILP Model Establishment

2.1. Model Description

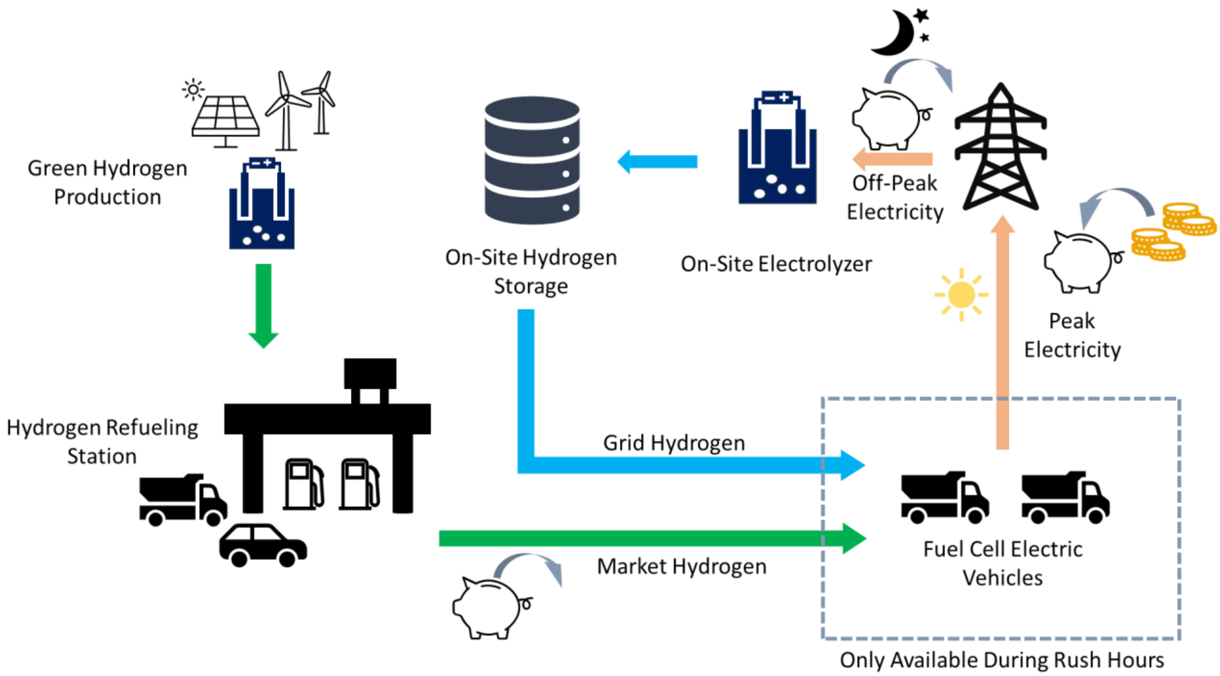

Figure 2-1 Schematic of the FCEV2G Using Hydrogen both from the Market and Produced Onsite

To investigate the profitability and social impact of FCEV2G, a model should be established to simulate a future FCEV2G station meeting specific criteria.

The FCEV2G station should have the following major elements:

- An onsite electrolyzer that produces hydrogen by using electricity from the grid
- An onsite hydrogen storage system where the hydrogen produced onsite is stored
- A system dispensing hydrogen into FCEVs and connecting them to the grid

Note that the FCEVs only contribute their fuel cells to FCEV2G without using hydrogen in the onboard hydrogen storage on FCEVs. In this way, the hydrogen bypasses the onboard storage and directly go to the fuel cells from the FCEV2G station. Pressuring hydrogen into high pressure involves costs and it is unnecessary for FCEV2G. More of this is discussed in Section 2.7.

The FCEV2G station operates with external conditions, including:

- A fleet of FCEVs in the traffic stream beside the FCEV2G station
- Access to a hydrogen market having low-carbon hydrogen produced through solar or wind power

Figure 2-1 illustrates the electricity and hydrogen pathways in a hypothesized FCEV2G station in line with these criteria and considered by this study. There are three energy carriers with different pathways:

- Green arrows are the pathway of low-carbon hydrogen from the hydrogen market going to hydrogen refueling stations and the FCEV2G station.
- Blue arrows are the pathways of hydrogen produced by the onsite electrolyzer then entering the onsite hydrogen storage and FCEVs.
- Orange arrows are electricity supplied by FCEVs to the grid and electricity drawn from the grid by the onsite electrolyzer.

Revenue is generated when FCEVs generate electricity. Expenditure occurs when inputting market hydrogen and grid electricity, as well as purchasing and maintaining the equipment. The difference between the revenue and expenditure is the net profit of this FCEV2G system, which can be shared by the FCEV owners and the FCEV2G operator. This model provides a structured framework for assessing the economic viability.

Hydrogen can be produced either by the onsite electrolyzer using grid electricity (referred to as grid hydrogen) or in large production sites powered by renewable energy sources (referred to as market hydrogen). The onsite electrolyzer strategically operates during off-peak hours characterized by lower electricity demand and consequently lower prices. Because of the ever-changing grid operation, the price and carbon intensity of the onsite produced hydrogen using grid electricity are also dynamic. In contrast to the grid hydrogen, the market hydrogen supplied by the fuel market is considered to have a stable price and stable carbon intensity. Grid hydrogen is stored in an onsite hydrogen storage tank after its production, and market hydrogen is transported to the nearby HFS via tube-trailers or pipelines, depending on the hydrogen market scale.

Once the electricity price becomes sufficiently high, FCEVs parking in the FCEV2G station are supplied with hydrogen fuel and connected to the grid. The FCs of the FCEVs generate electricity by using hydrogen fuel, and the generated electricity is sold to the grid. By using existing FCs in the FCEV fleet, a considerable amount of cost on FCs is saved, but it also comes with an opportunity cost because the FCEVs are temporarily taken out of transportation service. To reduce the economic cost of tying up the FCEVs, the electricity generation phase is specifically scheduled during traffic rush hours, occurring from 7:00 to 11:00 and 16:00 to 20:00. During these time periods, traffic congestion reduces the efficiency of transportation and makes the temporary utilization of these vehicles less costly. Additionally, the electricity peak hours largely coincide with traffic rush hours, which raises the profitability of utilizing FCEVs to generate electricity during this time. Note that these FCEVs will most probably first come as trucks because hydrogen power is advantageous over electric power especially in terms of heavy transportation.

As the FCEVs generate electricity and feed it into the grid, the cycle of electricity-hydrogen-electricity is completed, only the electricity becomes cheaper, cleaner, and more stable. In this process, hydrogen stores energy from cheaper grid electricity and renewable energy and releases the energy during high-demand time, contributing to a more reliable and sustainable energy ecosystem.

2.2. Mixed Integer Linear Programming

Optimization problems seek the optimal result in certain circumstances. For some of the optimization problems, the values of different variables are discrete, and the solution space is bounded by constraints so that only a subset of values represent valid solutions. These problems are called mixed integer linear programming (MILP) problems, which are usually defined by an objective function stating the optimization target and the constraints defining the solution space. Even for problems with continuous values, they can be converted to MILP problems as long as the error is within the tolerance threshold. For a MILP problem, the general form of its objective function can be expressed as below:

$$\sum_{max} a_i x_i \tag{2.1}$$

where, x_i are the integer variables and a_i are constants.

Each constraint can be expressed as the below:

$$\sum b_i x_i \leq B \tag{2.2}$$

where b_i and B are constants.

A simple MILP problem can be solved by hand, but many realistic MILP problems have very large numbers of variables, which makes conventional way of solving not applicable. By using existing solvers designed for solving MILP, the problem can be described in a compatible mathematical language and sent to the solvers. Once a valid MILP problem is mathematically formalized, it can be passed to an off-the-shelf MILP solver library, and the solution is obtained by the solvers.

2.3. Objective Function and Constraints

The profit achieved by this FCEV2G station is contingent on the precise timing and duration of the operation of each component, such as the electrolyzer and the fuel cells. To find the maximum profit in this FCEV2G station, a mathematical model must be established to determine the optimal schedule to run the local electrolyzer and the parked FCEVs. This optimization problem is formulated as a MILP mathematical problem. In the MILP problem considered by this study, the minimum time length is one hour, meaning that the electricity price and energy conversion power remain constant for one single hour. The start-up time and shut-down time are also not considered, or in other words, the components can reach the maximum operation level immediately.

The MILP formulation enables the system to find the ideal combination of component operation times within the constraints and objectives defined, ultimately leading to the highest achievable profit for the FCEV2G station. The objective of the MILP model is to maximize the total revenue, or in other words, the sum of revenues in each hour, during the whole analysis period. As mentioned in Section 2.1, the FCEV2G spends money on buying grid electricity and market hydrogen and earns money by selling electricity. Therefore, the revenue at hour *t* can be expressed as:

$$R(t) = \big(E_{FC2G}(t) - E_{G2E}(t)\big)P_{GE}(t) - E_{MH2FC}(t)P_{MH} \tag{2.3}$$

Here, $E_{FC2G}(t)$ and $E_{G2E}(t)$ are the energy from the fuel cells to the grid and the grid to the electrolyzer at hour t, namely the electricity generation and consumption of the FCEV2G station; $E_{MH2FC}(t)$ is the energy in the market hydrogen used in the FC operation; $P_{GE}(t)$ and P_{MH} are the prices of the grid electricity and market hydrogen, respectively. In this equation, the energy input, output, and grid electricity price are all time-variant except the market hydrogen price which is assumed constant. The grid electricity price is considered insensitive to the supply and demand change caused by this FCEV2G station because the electrolyzer input and fuel cell output are negligible compared to the total supply in Alberta, which is from 8,000 to 12,000 MW, and in Ontario, which is from 15,000 MWh to 20,000 MW.

Once the revenue at each hour is defined, the sum of these revenues at each hour is the objective function:

$$Obj = \sum R(t) \tag{2.4}$$

However, this objective function excludes the site cost, including the CAPEX and OPEX of all the equipment. This is because this part of the cost is constant regardless of the optimization result thus has no impact on the optimization. The optimization model disregards any fixed cost during its calculation. Therefore, the optimization is run on preset parameters including the electrolyzer size and market hydrogen price.

The energy flow of each process is decided by the optimization model but is also subject to the following constraints:

2.3.1. Direction Constraint

All the powers cannot be negative, meaning the energy flow can only happen in the directions indicated in Figure 1-2.

$$E_i \geq 0, i \in \{G2E, FC2G, E2HS, HS2FC, MH2FC\} \tag{2.5}$$

The meanings of these abbreviations of different energy flow pathways in the FCEV2G are shown in Table 2-1.

Table 2-1 Meanings of Abbreviations Concerned with Energy Flow within the FCEV2G Station

Name	Meaning
G2E	electricity from the grid to the onsite electrolyzer
FC2G	electricity from the fuel cells to the grid
E2HS	hydrogen from the onsite electrolyzer to the onsite hydrogen storage
HS2FC	hydrogen from the onsite hydrogen storage to the fuel cells
MH2FC	market hydrogen entering the fuel cells

2.3.1. Capacity Constraint

The input of the electrolyzer and the total output of the fuel cells are capped by their capacities:

$$E_{G2E}(t) \le Cap_{El} \tag{2.6}$$

$$E_{FC2G}(t) \le Cap_{FC} = N_v(t) \times O_{FCEV,max} \tag{2.7}$$

$$N_v(t) \le N_s \tag{2.8}$$

$$N_v(t) \le N_t(t) \tag{2.9}$$

Electrolyzer maximum input, Cap_{El}, is preset as constant in a single optimization. $E_{FC2G}(t)$ is capped by the product of the number of FCEVs participating in the FCEV2G at hour t, $N_v(t)$, and the maximum power output of one individual FCEV, $O_{FCEV,max}$. $N_v(t)$ is restricted by two other values, one is the available parking spot in the FCEV2G station, N_s, which is the maximum capacity of the station accommodating FCEVs; the other is $N_t(t)$, the number of passing-by FCEVs that are willing to stop and contribute their FCs to FCEV2G, the determination of which is discussed in 2.4.

2.3.2. Efficiency Constraint

The hydrogen entering the onsite hydrogen storage is the electrolyzer input, $E_{G2E}(\mathrm{t})$, times the electrolyzer efficiency, η_{El}. The electricity coming from the FCs and entering the grid is the total hydrogen use, $E_{HS2FC}(\mathrm{t}) + E_{MH2FC}(\mathrm{t})$, times the fuel cell efficiency η_{FC}.

$$E_{E2HS}(\mathrm{t}) = E_{G2E}(\mathrm{t}) \cdot \eta_{El} \tag{2.10}$$

$$E_{FC2G}(\mathrm{t}) = \left(E_{HS2FC}(\mathrm{t}) + E_{MH2FC}(\mathrm{t})\right) \cdot \eta_{FC} \tag{2.11}$$

2.3.3. Storage Constraint

The amount of onsite stored grid hydrogen at hour t, $A_{GH}(t)$, cannot exceed the storage capacity of the onsite hydrogen tank, Cap_{HS}, while it cannot be negative, either. The amount of onsite stored grid hydrogen at hour t is determined as the accumulation of incoming grid hydrogen from the electrolyzer, $E_{E2HS}(t)$, minus the accumulation of grid hydrogen leaving the storage to the fuel cells, $E_{HS2FC}(t)$.

$$0 \leq A_{GH}(t) \leq Cap_{HS} \tag{2.12}$$

$$A_{GH}(t) = \sum (E_{E2HS}(t) - E_{HS2FC}(t)) \tag{2.13}$$

2.3.4. Rush Hour Constraint

The fuel cells only work for FCEV2G during the rush hours, 7:00 to 11:00 and 16:00 to 20:00 every day. Note that the hours are discrete.

$$E_{FC2G}(\mathrm{t}) = 0, \text{if } (\mathrm{t}\, mod\ 24) \notin [7,11] \cup [16,20] \tag{2.14}$$

2.4. Traffic

The FCEV2G station is assumed to be situated beside a highway where some of the passing vehicles may choose to discontinue their journey and participate in the FCEV2G instead. The number of possible participating vehicles, $N_t(t)$, is determined by multiplying the ratio of trucks to total vehicles, r_{truck}, the market penetration rate of FCEVs in trucks, r_{pene}, and the drivers' willingness for participation, r_{will}, to the total passing traffic volume, $N_{total}(t)$. However, the multiplication of these values may generate non-integers, and the $N_t(t)$ value used in the model is converted to integers through Poisson distribution.

The traffic data is selected as the hourly traffic count at one point near Edmonton, in the segment of Alberta Provincial Highway No. 2 from Edmonton to Calgary. [91] Due to the lack of availability of hourly traffic data in Ontario in recent years, the Albertan traffic data are also used in the cases in Ontario.

$$N_t(t) = Poisson(r_{will} r_{pene} r_{truck} N_{total}(t)) \tag{2.15}$$

2.5. Carbon Emission Calculation

The carbon intensity of the FCEV2G electricity is the weighted average of the carbon intensity of every supply type: nuclear, gas, coal, etc.

$$CI(t) = \frac{\sum CI_i(t) \times S_i(t)}{\sum S_i(t)} \tag{2.16}$$

The historical data of supply breakdown of grid electricity in Alberta is found at an AESO website [92], and the data for Ontario is found at an IESO website [93]. IESO and AESO are the coordinators and integrators of the electricity systems in each province, offering the historical data of the power output of each generator at each hour and the energy types of these generators. The carbon intensity of different supply types is found in a report from IPCC [94], and the median values of carbon intensity for each power source are selected for this study which are shown in Table 2-2.

Table 2-2 Carbon Intensity of Different Types of Electricity Generation [94]

Types of Electricity Generation	Carbon Intensity (kgCO_2eq/MWh)
Biofuel	230
Coal	820
Gas	490
Hydro	24
Nuclear	12
Solar	48
Wind	12

Beside utilizing the electricity price difference, FCEV2G also changes carbon emissions (CE) of the grid because of the difference in carbon intensity (CI) of grid electricity at different hours. FCEV2G generates carbon emissions when consuming grid electricity, $CI(t) \cdot E_{G2E}(t)$, and market hydrogen, $CI_{MH} \cdot E_{MH2FC}(t)$, but also reduces carbon emissions by supplying electricity with low carbon intensity, $CI(t) \cdot P_{FC2G}(t)$. The total carbon emission change is the sum of both carbon increase and decrease:

$$CE(t) = CI(t) \cdot P_{G2E}(t) + CI_{MH} \cdot P_{MH2FC}(t) - CI(t) \cdot P_{FC2G}(t) \quad (2.17)$$

2.6. Grid Hydrogen Price

To compare the profitability of using market hydrogen and grid hydrogen, the price of grid hydrogen should be found and compared with the known and constant market hydrogen. Grid hydrogen price at hour t is defined as the value of remaining grid hydrogen at hour t divided by its amount in the onsite storage at hour t.

$$P_{GH}(t) = \frac{V_{GH}(t)}{A_{GH}(t)} \quad (2.18)$$

Then, the value of remaining grid hydrogen at hour t is the value at the previous hour plus the spending on the electricity used for producing the incoming grid hydrogen minus the value of the hydrogen leaving the onsite storage.

$$V_{GH}(t) = V_{GH}(t-1) + E_{G2E}(t)P_{GE}(t) - E_{HS2FC}(t)P_{GH}(t) \tag{2.19}$$

2.7. Site Cost Estimation

Different from ordinary FCEV operation where the hydrogen fuel is fed to FCs from onboard storage when the vehicle is on the road, in FCEV2G, the hydrogen fuel is converted into electricity. This means the onboard hydrogen storage is an unnecessary step for FCEV2G. Some HFS components such as compressors, cascades, and refrigeration units, which are designed to cope with the high pressure of onboard hydrogen storage (350 – 700 bar), are also unnecessary for FCEV2G. This may be technically viable regarding the pressure difference between the onsite storage tank (>15 bar) and the FC anode pressure (1 to 2 bar) [95], [96], [97]. There are projects evaluating the possibility of using existing natural gas pipelines to transport hydrogen to lower the delivery cost in case of a large amount of hydrogen demand in the future. The natural gas pressure in transmission pipelines is 50 bar to140 bar [98], and the anode pressure of hydrogen fuel cells is around 1 to 2 bar. It is possible to use the pressure difference between the hydrogen in the pipelines and fuel cell anode to fuel the hydrogen into the FCEVs. The output pressure (30 bar) of the electrolyzer is also much larger than that of hydrogen storage. [99] The configuration of such a fueling station can be the one shown in Figure 2-2, which only contains onsite storage and dispensers.

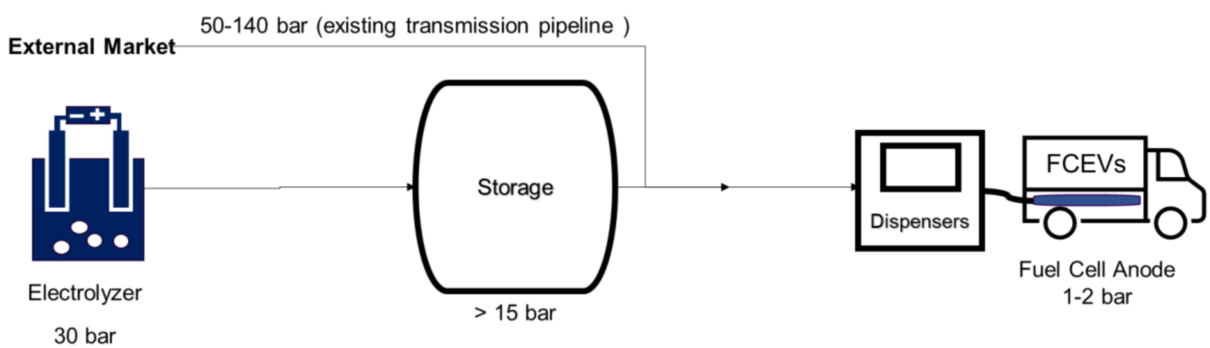

Figure 2-2 Schematic of a Fueling Station Showing Pressure Difference between Hydrogen Storage Tank and Fuel Cell Anode

The costs of the fueling station components are collected from the Hydrogen Delivery Scenario Analysis Model (HDSAM) from the Argonne National Laboratory [100], which is an Excel-embedded model. The FCEV2G station in this study adopts gaseous storage and high component cost reduction factors on dispensers. The cost of the electrolyzers is from Future Distributed Hydrogen Production from PEM Electrolysis from the National Renewable Energy Laboratory (NREL) [101], which considers a future scenario in 2030 with projected technological advancements in reducing electrolyzer cost. The cost related to tax, inflation, and other financial factors in these two sources are not included in the site cost estimation.

The total cost of the FCEV2G site is the sum of CAPEX and OPEX of every component. The CAPEX obtained from the source is the initial capital cost, $C_{Initial}$. In this study, it is annualized to each year within each component's lifetime, LT, and combined with the optimized annual profit to investigate the profitability of this FCEV2G station. The relation between $C_{Initial}$ and annualized cost, $C_{Annulized}$, is determined by the equation below [102].

$$C_{Annualized} = C_{Initial} \times \frac{dr(1+dr)^{LT}}{(1+dr)^{LT}-1} \tag{2.20}$$

2.8. Sensitivity

A sensitivity analysis is performed to evaluate the dependence of the optimization results on different parameters. The sensitivity of the net profit was examined concerning several parameters, including market hydrogen cost, onsite hydrogen storage maximum capacity, electrolyzer efficiency, fuel cell efficiency, number of parking spots for participating FCEVs, market penetration rate of FCEVs to trucks, willingness of participating truck drivers, and input capacity of the onsite electrolyzer.

The sensitivity is calculated over an extensive range of percent changes relative to the base case scenario and is numerically defined as below. The sensitivity of the optimization result toward a parameter is the relative change of the result, $\Delta R/R$, over the relative change of the parameter, $\Delta i/i$.

$$S_i = \frac{\Delta R/R}{\Delta i/i} \tag{2.21}$$

2.9. Software and Data

To better compare the amount of hydrogen and electricity consumed and produced, the unit of the energy of hydrogen and electricity is uniformized as MWh and the price accordingly USD/MWh. The original data of electricity price is in CAD and converted to USD by multiplying 0.75, an approximate currency exchange rate, to accord with the price unit of site components collected from HDSAM and NREL. The Excel-imbedded models of HDSAM and NREL are reconstructed in Python to flexibly adjust component sizes and exclude unwanted financial factors. The original price of market hydrogen is in CAD/kg and converted to USD/MWh by multiplying 0.75 and dividing it by 120 MJ/kg, the energy content of hydrogen [103]. The data sources of electricity and traffic data used in this study is listed in Table 2-3.

Table 2-3 Data Sources of Electricity and Traffic Data

Province	Data Type	Data Source	Remarks
Alberta	Electricity Price and Supply	AESO	The grid operator in Alberta
Alberta	Traffic Count	Government of Alberta	-
Ontario	Electricity Price and Supply	IESO	The grid operator in Ontario
Ontario	Traffic Count	Government of Alberta	To the best knowledge of the author, historical hourly traffic data are not available in Ontario, so data in Alberta is used.

Table 2-4 and Table 2-5 show the values used for the constant parameters and base case parameters in the optimization, respectively. Using market hydrogen generates costs in three different steps according to a report from Transition Accelerator [104]: production, processing and delivery, and fueling.

Table 2-4 Constant Parameters

Name	Value	Source	Remark
Storage CAPEX	8 \$/kWh	[105]	
Storage OPEX	0.08 \$/kWh/yr	[106]	Assumed as 1% of the CAPEX
Individual Fuel Cell Power Maximum Output	0.4 MW	[57]	Maximum Power Output of the TRE FCEV Model from Nikola Motor
Dispenser Lifetime	10 yrs	[100]	
Hydrogen Storage Tank Lifetime	20 yrs	[107]	
Electrolyzer Lifetime	20 yrs	[101]	
Annual Discount Rate	0.07	[107]	

Table 2-5 Base Case Parameters

Name	Value	Source	Remark
Fuel Cell Efficiency	50%	[108]	Median Value of Proton-Exchange-Membrane Fuel Cells
Electrolyzer Efficiency	60%	[109]	Approximate of Several Electrolyzer Models
Market Hydrogen Production Cost	3 $/kg	[104]	Median Value of Green Hydrogen with a Electrolyzer Capacity Factor of 68%
Market Hydrogen Processing and Delivery Cost	2 $/kg	[104]	Tube-Trailer Delivery of 5 km
Market Hydrogen Carbon Intensity	20 $kgCO_2eq/MWh$	[94]	Carbon Intensity of Wind Power over Electrolyzer Efficiency, typically 0.6
Electrolyzer Power Output	1 MW	-	When the Ratio of Usage of Market Hydrogen over Grid Hydrogen is Close to 1
Hydrogen Storage Size	10 MWh	-	Storage Enough for Storing 10 Hours of Maximum Electrolyzer Production (The impact of this factor is analyzed in Section 3.9)
Number of Available Spots	8	-	As a Typical Fueling Station
FCEV Truck Market Penetration Rate	6%	[110]	Median Value of a Forecast Range of the Market Penetration Rate of Fuel Cell Heavy-Duty Vehicles in 2030
Willingness Rate	0.6	[111]	Mean Ratio of Surveyed Population Supporting Energy Transition in Alberta
Truck Ratio	0.05	[112]	Ratio of Vehicles Weighting More than 4.5 t Versus Total Vehicle Registration in Canada from 2015 to 2019.

Chapter 3. Simplified Model on Revenue Optimization

3.1. Chapter Introduction

A problem regarding the different components of an FCEV2G station is formulated in the previous chapter. The FCEV2G station is modelled as mathematical variables and their relations are defined by the constraints. The next step is to find the highest possible profit generated by this station to show the profit potential of the FCEV2G station, which requires an optimizer to find the best operational scheme to achieve the highest profit.

This chapter summarizes the work of the first step of analyzing the optimization results with a simplified model. In this chapter, the operation of the FCEV2G station is simulated by the mathematical model introduced above and optimized by using the Python API of CPLEX, an optimizer from IBM. Due to the calculation power and data availability at that time, the optimization period is only the second half of the year 2022, from July to December. The maximum number of participating vehicles is altered to see its influence over the operation. The daily operational pattern of two cases is summarized and the proportion of using each type of hydrogen in each scenario is shown. The net profit and the cost of the FCEV2G station in each scenario are also shown. However, in this chapter, the historical traffic data is not included, and enough FCEVs are considered always available for the FCEV2G station. In addition, the fueling components include all the essential parts for an ordinary hydrogen fueling station, so the cost of compressors, cascades, and refrigeration units are included in the site cost. The electricity cost in this chapter is shown in CAD.

3.2. Operation Analysis

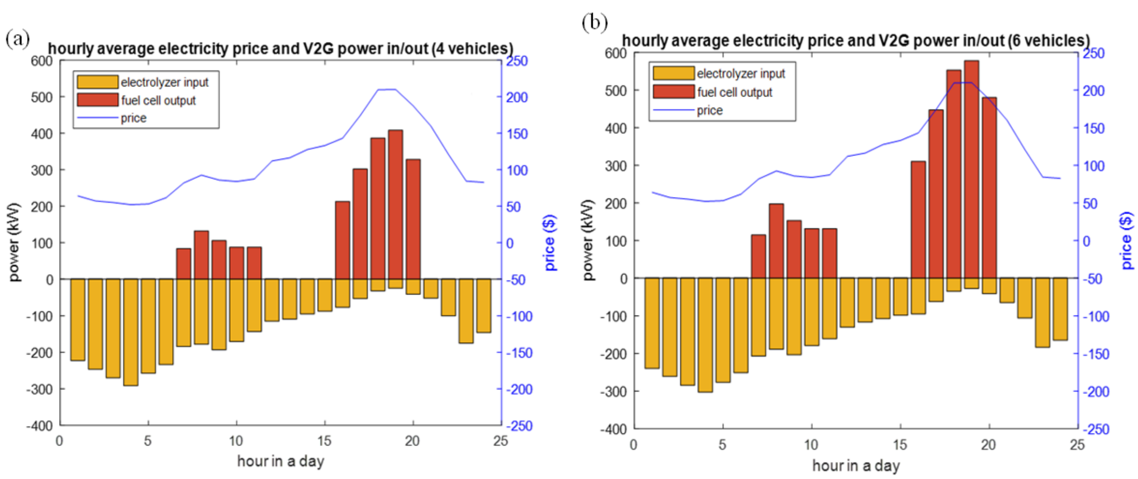

Figure 3-1 Hourly Average Electrolyzer and Fuel Cell Outputs for (a) 4-Vehicle and (b) 6-Vehicle FCEV2G Scenarios

The optimization was first performed using the data of Alberta at the number of vehicles 2, 4, 6, 8, 10, and 12. Figure 3-1a and 4b show the hourly average electricity price, electrolyzer power consumption and fuel cell power output for the 4- and 6-vehicle FCEV2G scenarios, which are obtained by averaging the values on each hour for the 184 days. The fuel cells are constrained to only operate during rush hours and the total power output increases considerably with more FCEVs. The electrolyzer is shown to operate mainly during off-peak hours but also runs from 16:00 to 20:00. However, the electrolyzer operating power increases disproportionally with that of the FCEVs. Note that the 24 hours in these graphs cannot be regarded as a real day for this is the average data of 184 days (4416 hours). There are many days astray from the usual peak-off-peak daily electricity demand/supply pattern. For example, the electrolyzer is shown in Figure 3-1 to run minimally during peak hours (16:00-20:00), but it only runs during off-peak hours on each actual day.

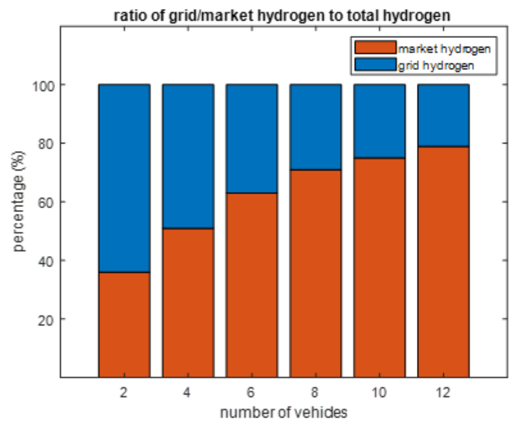

Figure 3-2 Ratio of Grid and Market Hydrogen to Total Hydrogen

Figure 3-2 shows the proportion of grid hydrogen and market hydrogen of the total hydrogen used by the FCEVs for different number of vehicles. The market hydrogen is shown to have a larger share when increasing the numbers of vehicles. In the 2-vehicle scenario, only one-third of total hydrogen is market hydrogen, but it quickly increases and reaches nearly 80% in the 12-vehicle. Increasing maximum fuel cell output encourages the electrolyzer to produce more hydrogen thus increasing the electrolyzer capacity factor. However, this encouragement wanes with higher maximum fuel cell output. This is because the market hydrogen becomes relatively cheaper when the electrolyzer must operate during more high-price hours to meet the mounting demand. The capacity factor is expected to stop rising when the average grid hydrogen price equals the market hydrogen price.

3.3. Cost Analysis

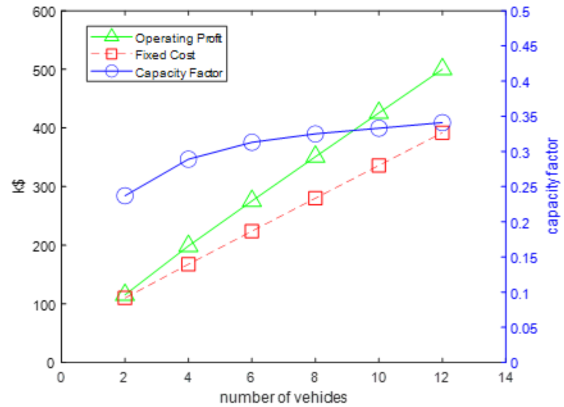

Figure 3-3 Operating Profit, Fixed Cost and Electrolyzer Capacity Factor Scenarios with Different Numbers of Vehicles

Figure 3-3 shows the operating profit, fixed cost, and electrolyzer capacity factor. The capacity factor is the total hydrogen produced from the electrolyzer over the maximum amount of hydrogen that the electrolyzer can produce in the same amount of time. The operating profit is the profit before considering the site cost, and is shown to increase 4 times from the 2–vehicle scenario to the 12–vehicle scenario, much more rapidly than fixed cost which only increases 2.5 times. With more vehicles available to connect to the grid, the increasing profit outruns the rising cost. One attribution of this is that FCEV2G uses the fuel cells in the FCEVs, hence increasing the maximum fuel cell output generates no cost of buying fuel cells but only requires larger compressors and other fueling station components. The addition of the available vehicles increases the maximum hydrogen-to-electricity power capacity, thus enabling the FCEV2G to exploit more of the rush-hour window and high-price hours. However, the degradation of fuel cells in the FCEVs due to FCEV2G is not considered in this study, and it may reduce the overall profit due to the earlier retirement of the fuel cells.

The capacity factor increases disproportionally with the profit. It increases from 27.1% in the 2–vehicle scenario to 31.3% at the 6–vehicle scenario but only increases to 34.1% in the 12–vehicle scenario. This indicates the profit increase from selling energy is not solely from the hydrogen stored by the electrolyzer, but also from consuming more market hydrogen.

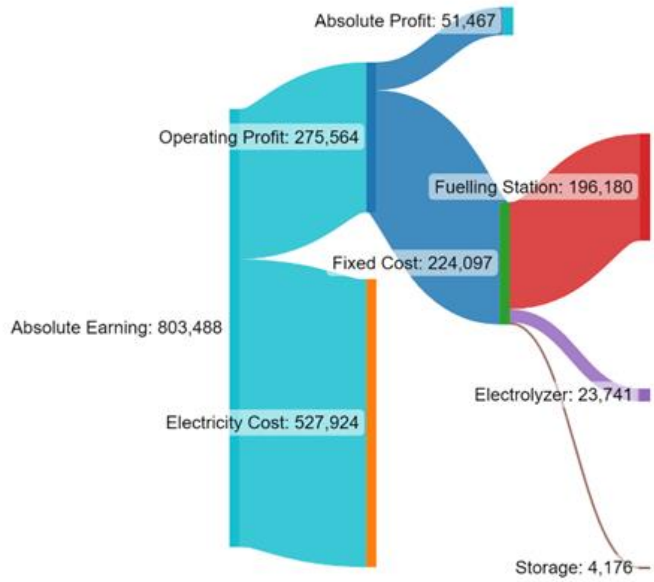

Figure 3-4 Cash Flow Chart for the FCEV2G Station

Figure 3-4 shows the breakdown of the cost and earnings for a 6-vehicle FCEV2G station, which provides an overview of the cash flow. In this case, the electricity cost negates 65% of the absolute earnings due to the high-efficiency loss in the roundtrip (i.e., electricity-hydrogen-electricity cycle). Regarding the fixed cost, almost 90% is attributed to the fueling station. The storage only accounts for a very small part of the total cost.

3.4. Carbon Emission Analysis

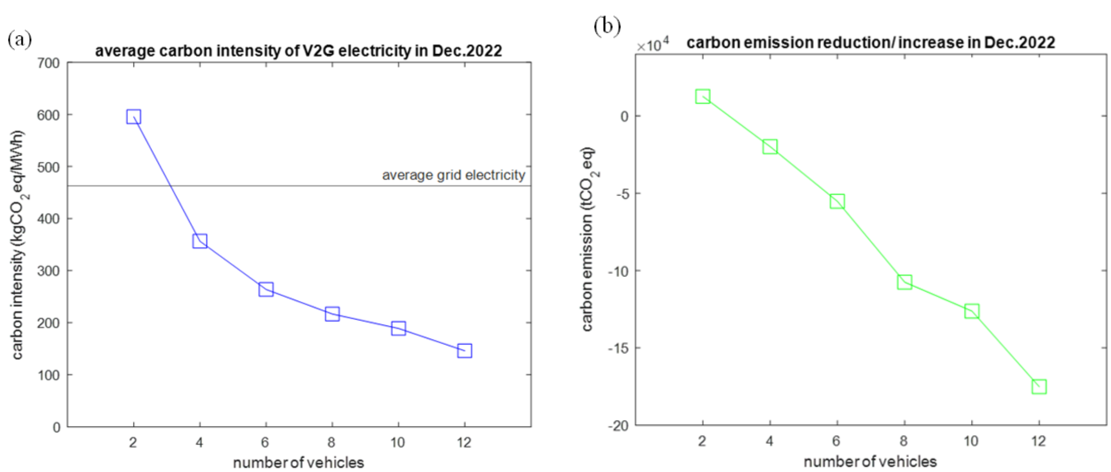

Figure 3-5 (a) Average Carbon Intensity of FCV2G Electricity and (b) Carbon Emission Reduction of FCV2G in December 2022

Figure 3-5a shows the carbon intensity of the electricity from FCEV2G with different numbers of vehicles, and the horizontal line represents the Albertan electricity carbon intensity without FCEV2G. Only December 2022 data is compared due to the availability of the data at the time. The carbon intensity of the 2-vehicle scenario is higher than that of the grid electricity but it rapidly declines with more FCEVs available to connect to the grid. This is due to more vehicles leading to lower grid hydrogen share, which has a much higher carbon intensity than market hydrogen. Figure 3-5b shows the total carbon emission change by this FCEV2G station, where being positive represents emission increase while negative indicates reduction. The profile of the total emissions has a similar trend to that of the carbon intensity but its declining speed does not slow down with more vehicles. This is because more vehicles connected to the grid result in not only overall cleaner hydrogen but also more total hydrogen amount.

Acknowledgement:

Parts of the contents in this chapter were presented in a conference and are published in its proceedings:

D. Ding and X. -Y. Wu, "Optimization of Fuel Cell Electric Vehicle-to-Grid in Alberta by Mixed Integer Linear Programming," 2023 IEEE 11th International Conference on Smart Energy Grid Engineering (SEGE), Oshawa, ON, Canada, 2023, pp. 43-47, doi: 10.1109/SEGE59172.2023.10274585

3.5. Optimization Using Alberta as a Case Study

3.6. Chapter Introduction

Alberta is a province in Canada with large fossil fuel reserves, including oil, gas, and coal. Its energy sector generates a large amount of profit, which contributes 20% to 30% of its total GDP [113] and helps it have the third highest GDP in Canada, more than 339 billion CAD in 2018, following Ontario and Quebec [114]. However, the reliance of its economy on fossil fuels leads to a significant amount of carbon emissions, and its monotonous supply of power makes its electricity price volatile and carbon-intensive. Thus, FCEV2G has a large potential of dealing with the price volatility and carbon emissions. A plan to construct a hydrogen railway line was announced by Canadian Pacific Railway in Alberta in 2020 which was the first plan of developing line-haul hydrogen-powered locomotives in North America. The company is reported to build hydrogen infrastructure at its Edmonton and Calgary sites including a 1 MW electrolyzer. [115] The hydrogen trains on this railway line can participate in FCEV2G when it is idle in the rail station.

This chapter discusses the result of a more complex model compared to Chapter 3. Here, the road traffic volume, FCEV market share, and participating willingness are integrated into the model. In addition, the cost of the FCEV2G site excludes components such as compressors and coolers which are essential to an ordinary hydrogen refueling system but unnecessary for an FCEV2G station. The solver for the MILP problem is changed to Gurobi (academic version) and its Python API. The grid electricity price and supply are first discussed in this chapter, followed by revenue optimization, which is the focus of this chapter. The result of the revenue optimization is first discussed in the base cases and then the results in different cases with different parameters and data are also discussed. Next, the carbon impact of FCEV2G is evaluated by investigating the carbon emission reduction of the revenue-optimized cases and the carbon-optimized cases.

3.7. Grid Electricity in Alberta

3.7.1. Electricity Price in Alberta

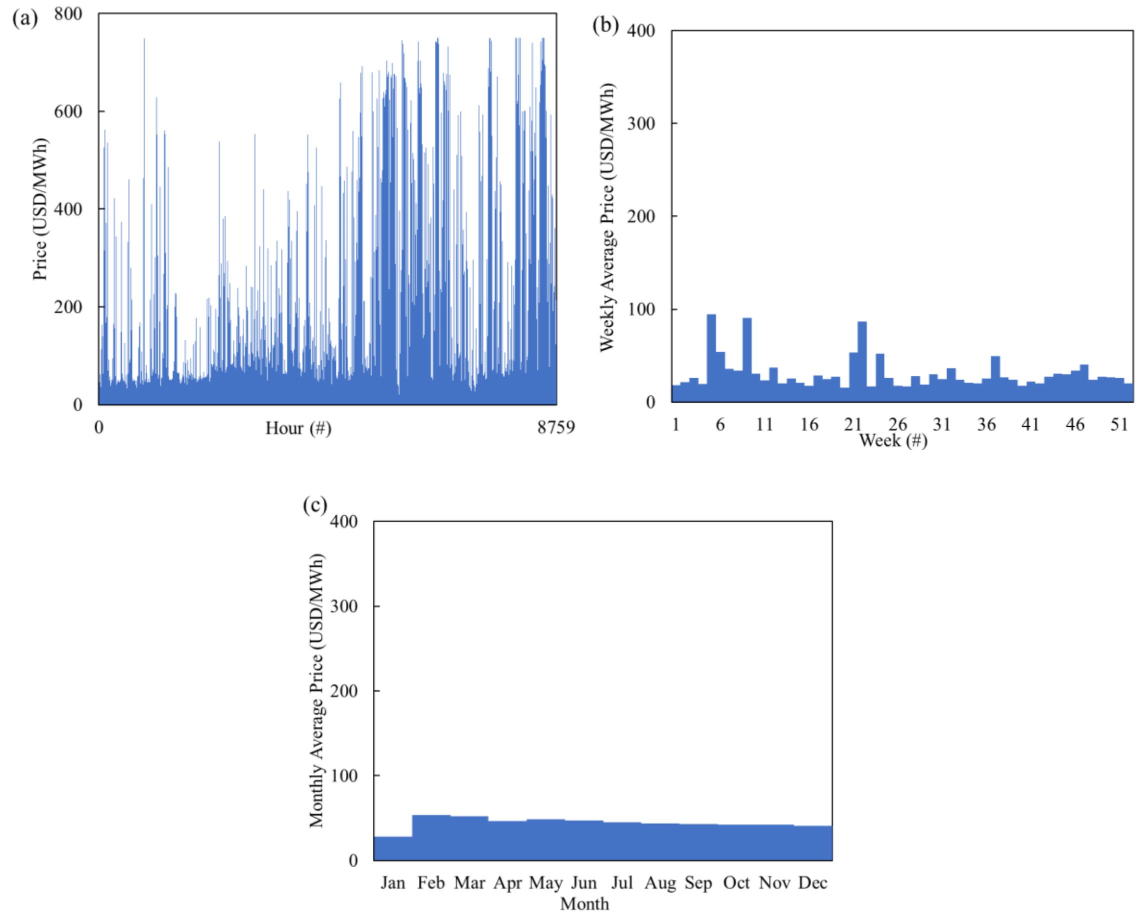

Figure 3-6 Grid Electricity Price in Alberta (a) at Each Hour, (b) Weekly Average, and (c) Monthly Average in 2019

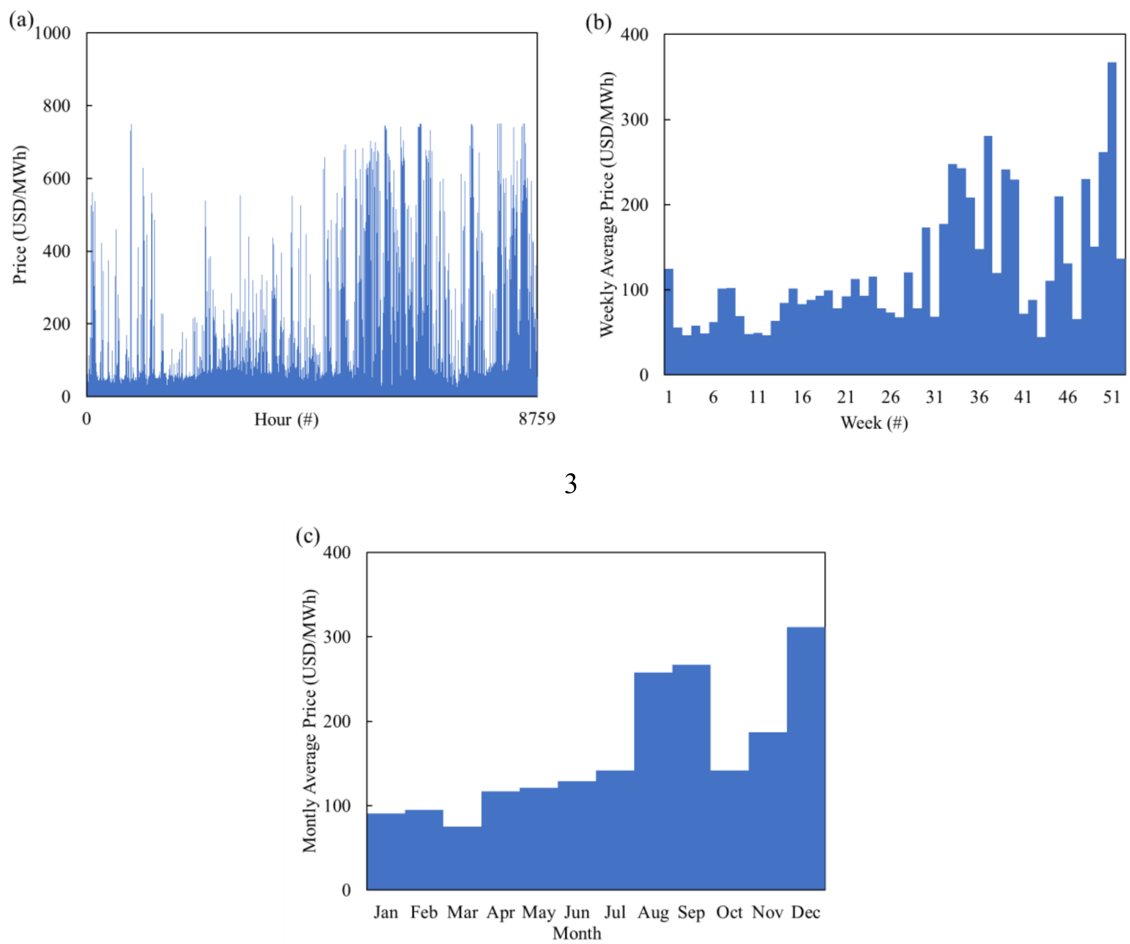

Figure 3-7 Grid Electricity Price in Alberta (a) at Each Hour, (b) Weekly Average, and (c) Monthly Average in 2022

The profit optimization is based on the grid electricity price at each hour. Figure 3-6 presents the 2019 hourly grid electricity price shown on different time scales and Figure 3-7 presents the data in 2022. The data in 2022 are selected in the base case study because of the high and unstable electricity price in 2022. Figure 3-6a and Figure 3-7a show the original data of electricity price across all 8,760 hours in 2019 and 2022. Notably, the latter half of the year features densely clustered tall columns in 2022, indicating an increased number of high-price hours during this period. In contrast to high-price hours, the low-price hours exhibit relatively stable values. This suggests that, compared to peak prices, off-peak prices vary much less throughout the year. To smooth the data and show a trend of price change in the year, the monthly and weekly electricity price is shown in Figure 3-6b, c and Figure 3-7b, c. The prices are shown to be very high in August, September, November, and December in 2022, likely because of the heightened electricity demand for cooling and heating. The higher weekly/monthly average price stem from the sharp increase in peak prices, as observed in Figure 3-7a rather than uniform price increase across the peak and off-peak price increase.

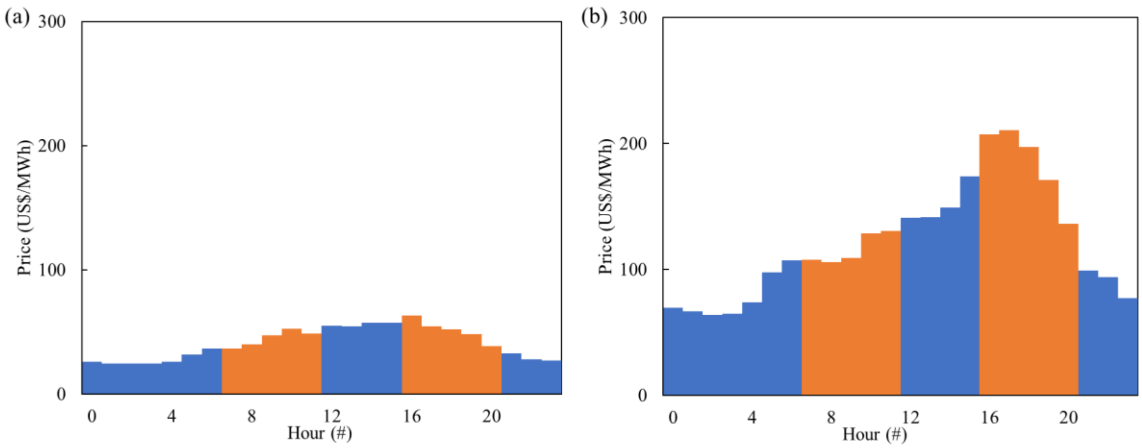

Figure 3-8 Average Grid Electricity Price at Each Hour of the Day in Alberta (a) in 2019 and (b) in 2022

Figure 3-8 provides insights into the average electricity price at different hours of the day in Alberta. The prices during highway rush hours are highlighted as orange columns, and the rush hours are shown to closely align with the peak hours especially the second rush hour period. The data highlights that grid electricity is the most economical around 3:00 and becomes costliest around 17:00. The highest average price is at 17:00 in both years, 63 USD/MWh in 2019 and 211 USD/MWh in 2022, around 3 times the lowest price at 2:00, which is 24 USD/MWh in 2019 and 64 USD/MWh in 2022. The price difference between the low-price hours and the high-price hours underscores the rationale for using hydrogen to store grid electricity. The difference between two years also suggests a trend of increasing electricity cost and price instability in Alberta. Please note that the price difference shown here is on an average basis and the actual hourly prices are much more extreme. Nevertheless, the graph provides valuable information of the daily price trends and the opportunity to leverage hydrogen storage to capture value during peak or high-price hours.

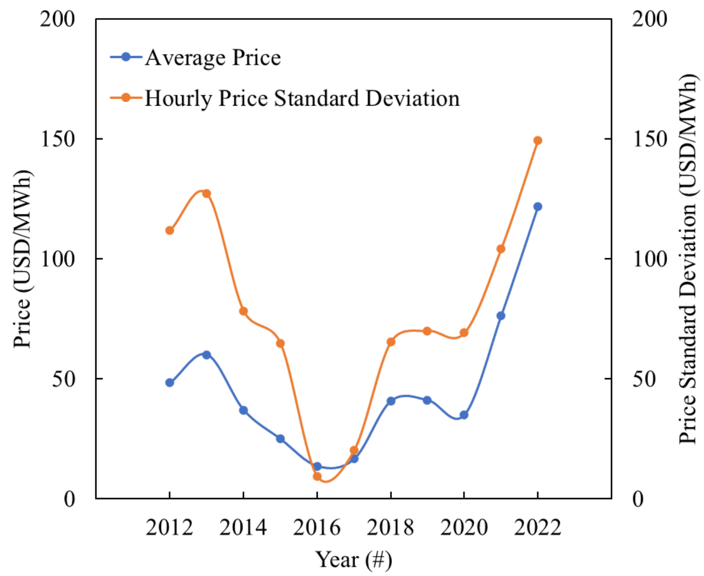

Figure 3-9 Average and Standard Deviation of the Grid Electricity Price in Alberta

Electricity prices in Alberta have shown a significant and growing trend of becoming higher and more volatile over the past 7 years, from 2016 to 2022. Figure 3-13 presents the average price and hourly price standard deviation each year starting from 2012. Over this 7-year period, the average electricity price has surged from 14 USD/MWh to 122 USD/MWh, making a 7.7-fold increase. This remarkable increase underscores the changing landscape of electricity costs in the region. The standard deviation of hourly electricity price, which serves as an indicator of data volatility, has increased by 16 times. The average and standard deviation of the price share a similar trend, indicating the relevance between the two. This notable increase in volatility suggests a growing disparity between the demand and supply. It is noteworthy that the average and standard deviation of the price share a similar trend. This suggests a connection between the two, likely arising from that the discrepancy between demand and supply does not uniformly elevate electricity prices at every hour but results in higher costs during peak-demand periods, making peak electricity increasingly more expensive than off-peak electricity.

The rising electricity prices and their increasing instability, as discussed in Section 1.1.2, imply that this situation will intensify in the future. This information highlights the importance of adopting energy storage techniques to combat the growing supply-demand mismatch and increasing volatility of electricity prices, and also ensure a stable and cost-effective energy supply.

3.7.2. Electricity Supply and Carbon Intensity in Alberta

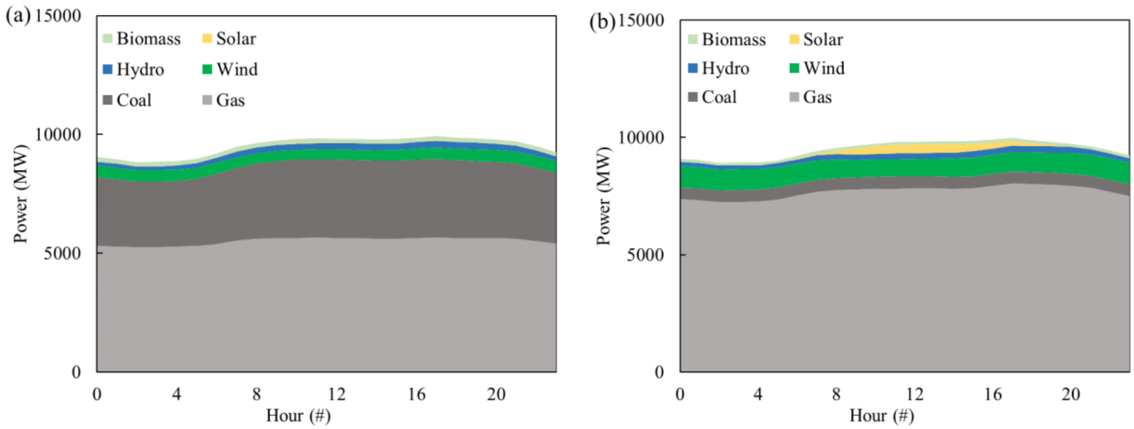

Figure 3-10 Yearly Average Supply of Different Types of Power Generation at Each Hour in the Day (a) in 2019 and (b) in 2022

Figure 3-10 shows the average carbo intensity of grid electricity in Alberta at each hour in a day in 2019 and 2022. The original electricity supply data from AESO shows the Albertan grid electricity supply categories include gas, coal, wind, hydro, solar, biomass, wood/refuse, gas cogeneration, dual fuel, and oil/gas. To simplify the supply breakdown and carbon intensity calculation, wood/refuse is combined with biomass, while gas cogeneration, dual fuel, and oil/gas are grouped with gas. This figure reveals the fossil fuel dominance in Albertan electricity supply: gas and coal provide most of the grid electricity in Alberta and provide the base load. However, their share in the overall power supply declined from 91% in 2019 to 86% in 2022. This shift is due to an 83% reduction of coal use, partially offset by a 28% increase in natural gas use. Renewable energy sources (wind, solar, biomass, and hydro) have seen a 49% increase in their contribution to the grid, which is primarily driven by the 57-fold expansion of solar supply and the 79% increase of wind supply. The daily pattern reveals that the peak supply time typically occurs from 8:00 to 18:00, while the lowest trough occurs around 4:00. Notably, the renewable power supply is shown to be statistically stable throughout the day, and the supply change is contributed most by coal in 2019 and by gas in 2022. In summary, the Alberta grid continues to rely heavily on fossil fuels, although their overall proportion has declined from 2019 to 2022. Peak grid supply is still heavily supported by increasing fossil fuel usage, despite the significant rise in renewable energy sources. This highlights the ongoing transition toward cleaner energy while acknowledging the substantial role of fossil fuels in maintaining grid stability during peak demand periods.

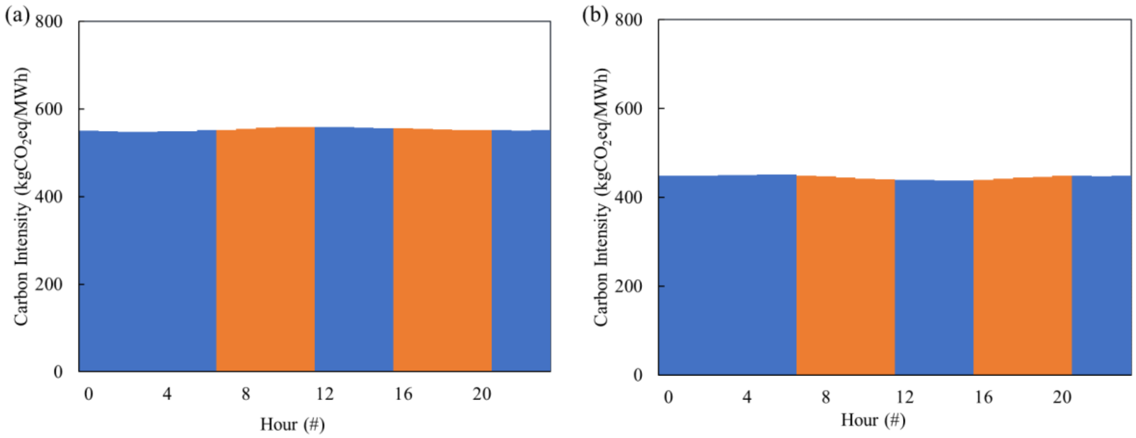

Figure 3-11 Yearly Average Carbon Intensity at Each Hour in the Day (a) in 2019 and (b) in 2022

Carbon intensity of the grid electricity is dependent on the source of power generation. Given that most of the electricity is produced from gas and coal at each hour throughout the day in both 2019 and 2022, the carbon intensity is constantly high but stable, staying in the range of 547 $kgCO_2eq/MWh$ to 559 $kgCO_2eq/MWh$ in 2019 and in 438 $kgCO_2eq/MWh$ to 451 $kgCO_2eq/MWh$ 2022. Unlike in Ontario, the grid carbon intensity exhibits no distinctive peak hours and off-peak hours. The carbon intensity in the daytime is slightly higher than that in the nighttime, but this is reversed in 2022, likely owing to the solar power generation increase during the daylight hours. The grid carbon intensity became lower in 2022 is primarily a result of the significant reduction of coal use, which is the most carbon-intensive energy source. Furthermore, the expansion of solar and wind power generation also contributes to this positive transition.

3.8. Base Case Analysis in Revenue Optimization

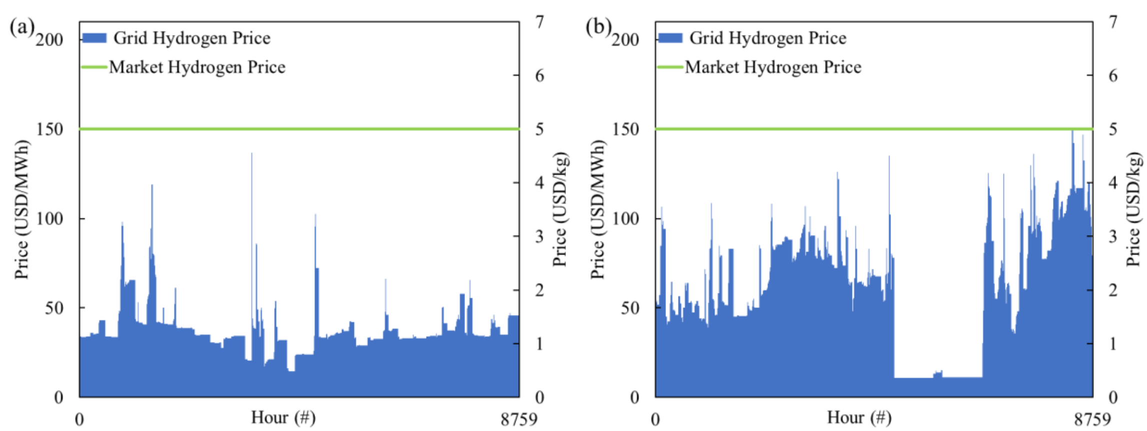

Figure 3-12 Price of Grid Hydrogen and Market Hydrogen at Each Hour in (a) 2019 Base Case and (b) 2022 Base Case

When the price of the electricity produced by the FCEV2G station falls below that of the grid electricity, the FCs of the FCEVs parking in the station start to operate and supply electricity to the grid. However, because there are two types of hydrogen, namely grid hydrogen and market hydrogen, the station must decide to use which type of hydrogen at each hour. Grid hydrogen is characterized by no delivery cost and the potential to utilize very cost-effective electricity for its production, while market hydrogen is assumed to have unlimited availability and a stable price. Figure 3-12 shows the hourly grid hydrogen price (depicted in blue) and market hydrogen (represented by a green horizontal line) in the 2019 and 2022 base case. Note that the grid hydrogen price shown in the figure only reflects the electricity cost of producing hydrogen, while excluding the fixed site cost of station components as it is not part of the optimization. The graph demonstrates that grid hydrogen price exhibits a notably higher stability compared to the grid electricity price. This stability is attributed to the electrolyzer's ability to selectively operate during low-price hours. The large and flat trough in Figure 3-12b is because there was no traffic from July 19th to September 30th due to road construction, when the electrolyzer has ample time to select the hours with the most cost-effective grid electricity. The annual average grid hydrogen electricity price is 37 USD/MWh in 2019 and 61 USD/MWh in 2022, 25% and 40% of the market hydrogen price, respectively. This significant price differential underscores the advantage of grid hydrogen utilization. The grid hydrogen price at each hour is always lower than market hydrogen price, because there is no incentive to produce onsite hydrogen if it proves to be more expensive than market hydrogen. Nevertheless, if the cost of electrolyzer is included, the grid hydrogen price rises to 187 USD/MWh, which underscores the significant impact of electrolyzer costs on hydrogen production. Electrolyzer sizing and how it impacts the grid hydrogen price is further discussed in Section 3.10.

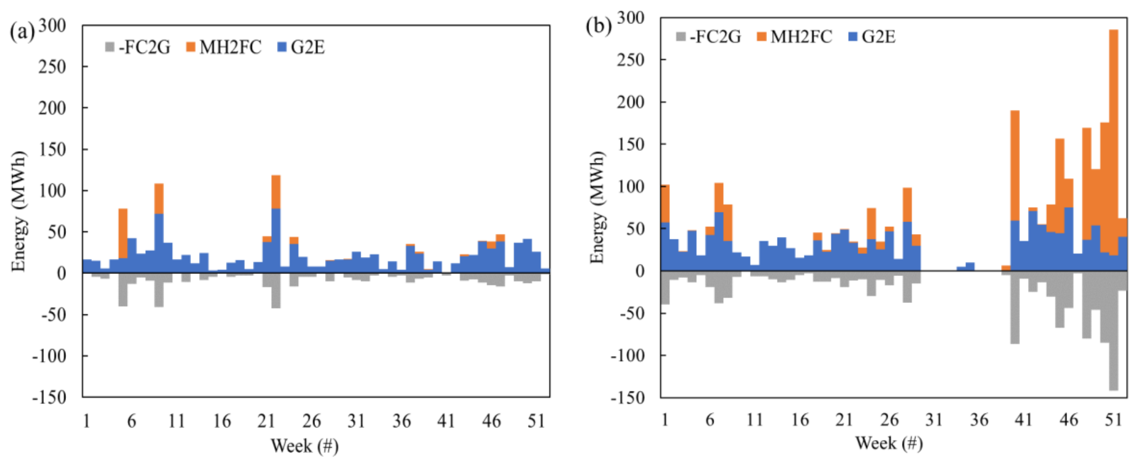

Figure 3-13 Amount of Electrolyzer Input, Fuel Cell Output, Grid Hydrogen Consumption, and Market Hydrogen Consumption (a) in 2019 and (b) in 2022 Base Case

The operation of the FCEV2G station is based on a dynamic decision-making process, taking into account the relationship between grid electricity prices, hydrogen prices, and the efficiency of the FCs. FCEV2G electricity price is the price of hydrogen divided by FC efficiency. When the grid electricity price surpasses the FCEV2G electricity prices, the station determines whether to generate electricity and the proportion of using each type of hydrogen. The optimization model makes decisions on the extent of operation of electricity buying, electricity selling, and market hydrogen buying, all bounded by the preset constraints. The operation strategy is such that electricity selling only happens when its price is exceptionally high, and the buying only happens when the price is exceptionally low. As a result, the operation hours when either the electrolyzer or the fuel cells are running are sparsely distributed. Figure 3-13 illustrated the patterns of energy buying and selling on a weekly basis, represented by the average values at every hour in that week. G2E and MH2FC are positive, indicating the system consumes energy by buying grid electricity and market hydrogen; FC2G is shown negative values, indicating that the system sells electricity to the grid. FC2G is generally shorter than the sum of G2E and MH2FC because of the efficiency loss incurred in the electrolyzer and fuel cells. It is noteworthy that FC2G exactly equals the round efficiency times the sum of both the energy inputs, reflecting the conversion process. The energy buying and selling show a similar trend on a weekly basis, saying the hydrogen storage input and output are quite rapid.

Despite the cost advantage of grid hydrogen, market hydrogen is still used at some hours. The decision to use market hydrogen is found to be specifically guided by the following conditions: 1. The grid electricity price must be higher than 300 USD/MWh, equal to market hydrogen price divided by FC efficiency. This condition ensures that the electricity generated by using market hydrogen remains cost-competitive with grid electricity. 2. The onsite hydrogen storage is empty or approaching depletion. It is intuitive to generate competitively priced electricity using market hydrogen when grid hydrogen is not available. As for using market hydrogen when using grid hydrogen, it is found that the first hour of grid hydrogen depletion following the market hydrogen usage is exactly when FC operation stops, which is either because grid electricity price drops below 300 USD or rush hours are over, making it advantageous to use market hydrogen.

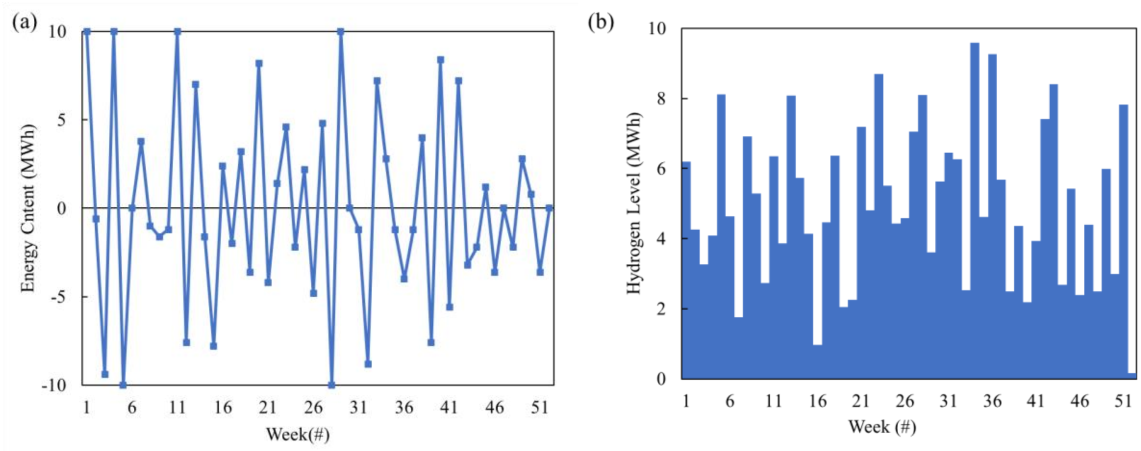

Figure 3-14 (a) Weekly Change and (b) Weekly Average Level of Grid Hydrogen in the Onsite Storage Tank in 2019 Base Case

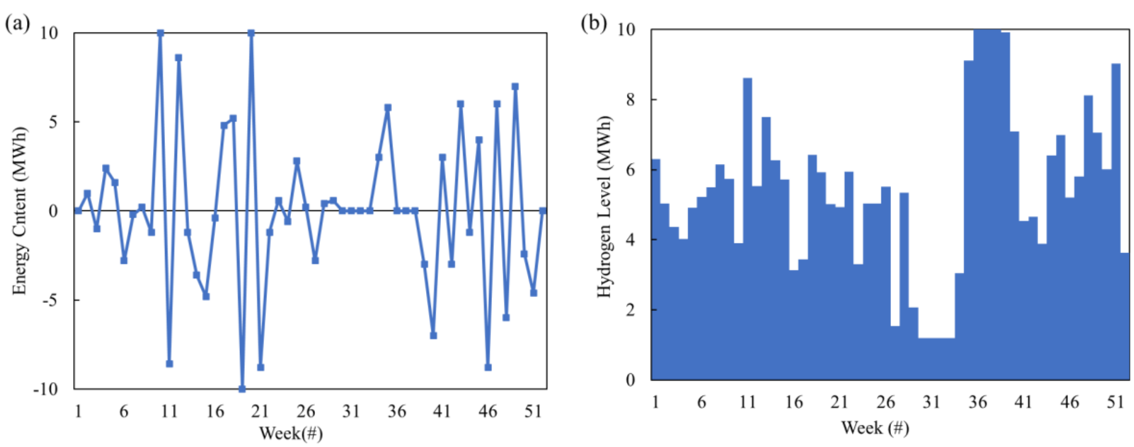

Figure 3-15 (a) Weekly Change and (b) Weekly Average Level of Grid Hydrogen in the Onsite Storage Tank in 2022 Base Case

Figure 3-14 and Figure 3-15 provide valuable insights into the on-site hydrogen storage dynamics within the FCEV2G station in 2019 base case and 2022 base case, respectively. Figure 3-14a and Figure 3-15a depict the weekly change of the amount of hydrogen in the onsite storage tank in each week. This variation is calculated as the difference between the hydrogen levels at the beginning and the end of each week. The positive and negative values in these graphs represent the changes in the hydrogen reserve and correspond to periods of low and high electricity prices. Figure 3-14b and Figure 3-15b, on the other hand, demonstrate the weekly average of the onsite hydrogen reserve. The fluctuations observed in the on-site hydrogen storage reflect its dynamic relationship with electricity prices. Notably, during the road construction period in 2022, the onsite storage was filled using the cheapest electricity and waits to be used during the high-price hours after the construction. The significant oscillation in on-site hydrogen levels underscores the seasonal energy transfer capabilities of the FCEV2G system, effectively harnessing grid electricity fluctuations. This not only benefits the FCEV2G station's profitability but also contributes to grid stability and sustainability by efficiently managing energy resources.

Table 3-1 Annual operation Data in 2019 and 2022 Base Case

Name	2019	2022	2019	2022
Annual Operating Hours	Total (#)	Total (#)	Share of Eligible Hours (%)	Share of Eligible Hours (%)
Electrolyzer Input	1,329	1,603	12.80	18.30
Market Hydrogen Buy-in	46	262	1.26	7.18
Fuel Cell Output	178	410	4.44	11.23
Annual Capacity Factor	Total (MWh)	Total (MWh)	Capacity Factor (%)	Capacity Factor (%)
Electrolyzer Input	1,308.69	1562.70	12.41	17.84
Market Hydrogen Buy-in	178.40	1222.40	-	-
Fuel Cell Output	459.60	1080.00	100	100

Table 3-1 reports the annual operation data in the 2019 and 2022 base case. The top half of the table reports the number of total operating hours and its share of eligible hours in the year of the different components, including the onsite electrolyzer, market hydrogen buy-in, and the fuel cells. The eligible hours for the electrolyzer encompass the entire year, while they are limited to the rush hours for market hydrogen buy-in and fuel cells and excluded from the construction period. The bottom half reports the gross annual energy input of electrolyzer operation and market hydrogen buy-in, and energy output of the fuel cells. The electrolyzer capacity factor is calculated by dividing its annual hydrogen production by the product of its production capacity and the number of hours in a year. Similarly, the FC capacity factor is calculated by dividing the annual electricity generation by the product of the individual FC capacity and the number of occupied vehicles.

Key observations from the table include the following. First, the capacity factor of the electrolyzer is slightly smaller than the share of the whole year due to some hours when the electrolyzer runs only partially. Second, the electrolyzer input in 2022 is 1.2 times that in 2019 while market hydrogen buy-in increases by nearly 6 times. This significant surge in market hydrogen use is caused by the dramatic increase in electricity price over the 3 years between 2019 and 2022, when it has multiplied almost 3-fold. However, the onsite hydrogen production increases by a much smaller margin, growing by only 20% over the same period. Third, the capacity factors of the electrolyzer in the two years are rather low, standing at below 20%. This means the electrolyzer only works for a small part of the time in a year, which makes the CAPEX on the electrolyzer account for a substantial proportion of the levelized grid hydrogen cost as calculated above. The fuel cell capacity factors, on the contrary, are 100% in both cases, meaning every FCEV occupied in the FCEV2G station always runs at maximum power. These findings shed light on the operational dynamics of the FCEV2G station, especially in the context of hydrogen production and utilization, and demonstrate how the system adapts to changes in electricity prices and demand.

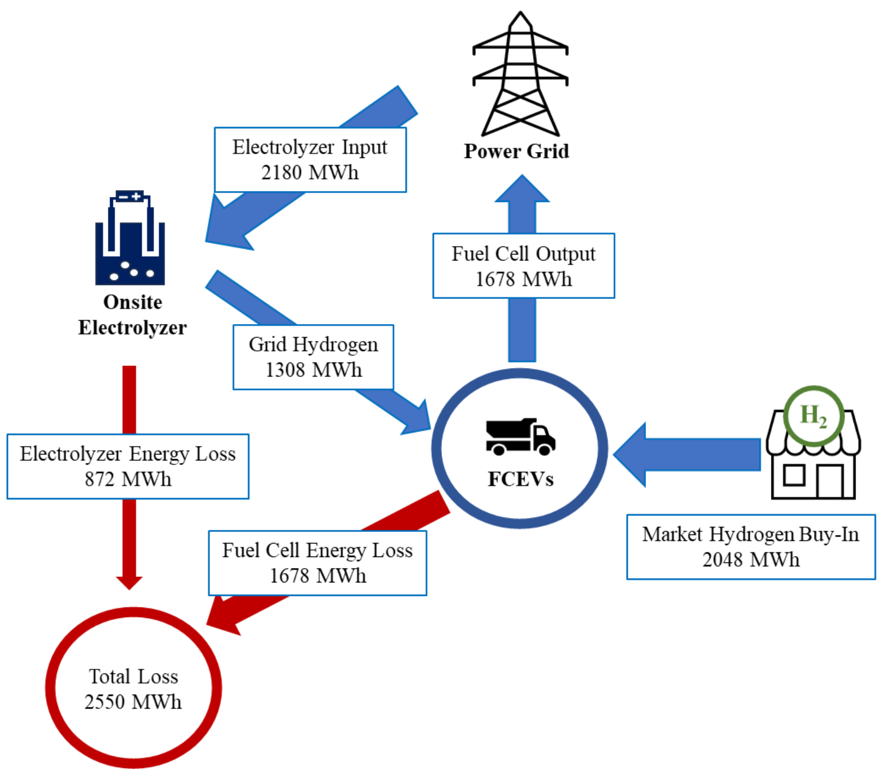

Figure 3-16 Energy Flow in FCEV2G in the 2022 Alberta Base Case

Figure 3-16 illustrates the energy flow between different components of the FCEV2G process. There is a large amount of efficiency loss at the onsite electrolyzer and fuel cells. A total amount of 4228 MWh comes into the system, then 1678 MWh is supplied back to the grid and 2550 MWh becomes waste heat, which accounts for 60% of the total energy input. The large amount of energy waste is a result of the low efficiency of energy conversion components, namely the electrolyzer and fuel cells, compared to batteries that have close to 100% energy conversion rates [116]. This suggests that FCEV2G is more suitable for where there is large renewable energy production whose unstable output is easier to be stored as hydrogen than transmitted via the electric grid, and this process is abstracted as using market hydrogen in this study. In addition, Hydrogen requires less space and less cost for energy storage. [117] Furthermore, the higher amount of energy waste from the fuel cells than the electrolyzer suggests increasing fuel cell efficiency will have a higher impact on FCEV2G than increasing electrolyzer efficiency.

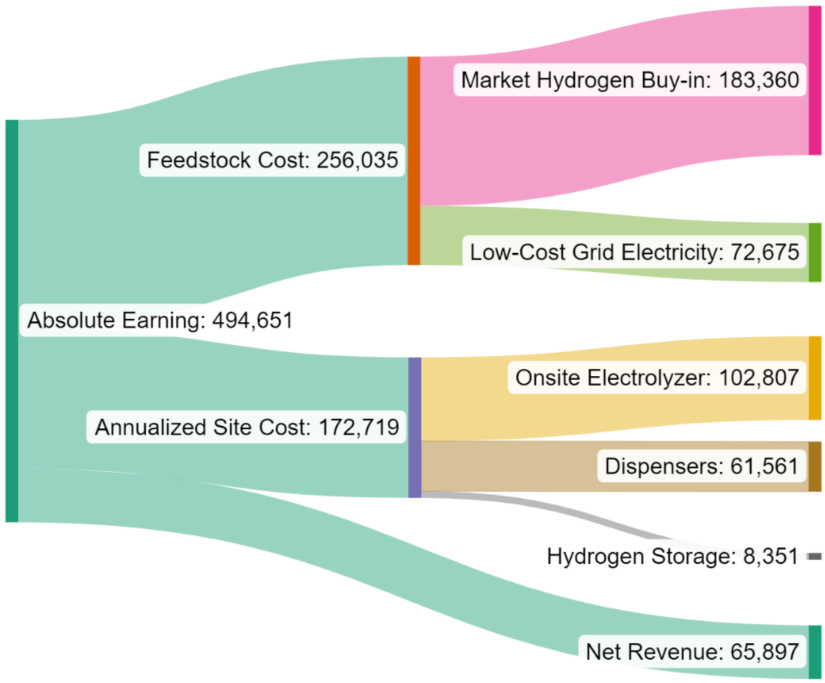

Figure 3-17 Cash Flow of 2022 Base Case in Alberta (Values in USD)

Figure 3-17 provides a detailed breakdown of the revenue and expenditure in each step of the 2022 base case for the FCEV2G system. The site cost is the combination of annualized CAPEX and OPEX. The annualization of the CAPEX uses the method discussed in Section 2.7. Selling electricity during high-demand hours creates 494,651 USD of earnings. The largest amount of expenditure, 52% of the absolute earnings (amounting to 256,035 USD), is allocated to buying market hydrogen and low-cost grid electricity. 35% of the absolute earnings (equivalent to 172,719 USD) is spent on the FCEV2G site. After accounting for expenses, the net profit amounts to 65,897 USD, which constitutes 11% of the absolute earnings. Most of the feedstock cost comes from purchasing market hydrogen, even though market hydrogen usage is less than grid hydrogen because market hydrogen is more expensive as discussed above. 102,807 USD is spent on the onsite electrolyzer, indicating a substantial portion of the total cost. 61,561 USD is allocated to dispenser-related expenses, and storage cost only constitutes a relatively small part of the overall expenditure. The figure provides a comprehensive view of the financial dynamics of the FCEV2G system in the 2022 base case, illustrating how revenue from electricity sales is allocated among various expenses and ultimately results in net profit.

3.8.1. Impact of Profit Optimization Result on Carbon Emissions

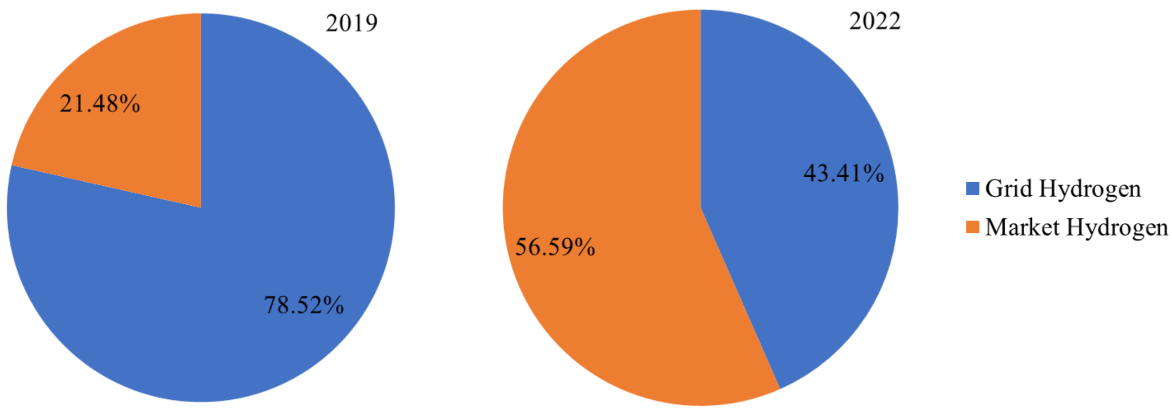

Figure 3-18 Grid Hydrogen and Market Hydrogen Percentage to Total Hydrogen Use in 2019 Base Case and 2022 Base Case

Because of the stable carbon intensity in Alberta and the efficiency loss of hydrogen production, grid hydrogen cannot find low-carbon-intensity hours for its production in Alberta in the base case, and it is consequently more carbon-intensive than grid electricity. However, the carbon intensity can still be reduced by using low-carbon market hydrogen. Using the maximum optimized profit schedules, carbon emissions can be reduced by 185 t in 2022. By considering the carbon tax in Canada, which was 50 CAD/tCO_2 (37.5 USD/tCO_2) in 2022 [118], an extra saving of 6,938 USD is also created. In contrast, in 2019, carbon emissions increase by 352 t due to different levels of market hydrogen utilization.

The ratio of using market hydrogen over grid hydrogen is a key factor in understanding the different carbon emission impacts of the FCEV2G station in the 2019 base case and 2022 base case. Figure 3-13 shows the proportion of FC consumption of two types of hydrogen in the base case in the two years. In the 2022 base case, the FCEV2G station relies significantly more on market hydrogen, with this type of hydrogen accounting for 56.59% of the total hydrogen consumption. In contrast, the 2019 base case uses a much lower proportion of market hydrogen, and it makes up only 21.48% of the total hydrogen consumption. This substantial increase of using market hydrogen from the 2019 case to the 2022 case, as opposed to grid hydrogen, is driven by the higher grid electricity price that makes electricity generation from market hydrogen more profitable, and meanwhile making the process more environmentally friendly. The change in the hydrogen usage composition also illustrates the FCEV2G station's ability to adapt its hydrogen procurement strategy based on market conditions, optimizing economic outcomes.

3.9. Sensitivity Analysis in Revenue Optimization

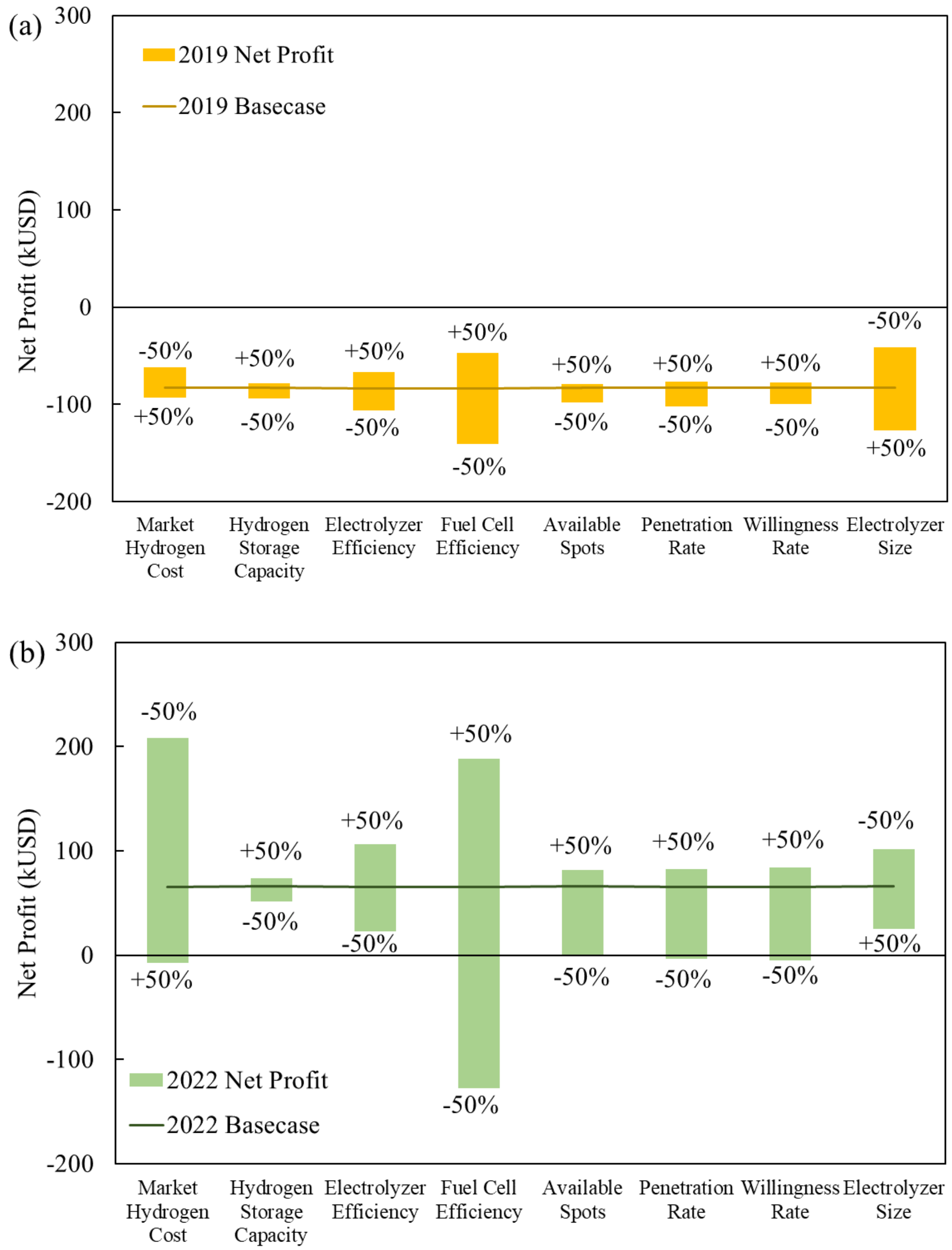

Figure 3-19 Variations from the Base Case for Changing Each Parameter Concerning the Profit Optimization (a) in 2019 and (b) in 2022

Table 3-2 Sensitivity of Net Profit toward Each Parameter

Name	2019	2022	Name	2019	2022
Market Hydrogen Cost	-10.45	-42.50	Available Spots	6.17	24.57
Hydrogen Storage Capacity	5.27	7.41	Penetration Rate	8.39	28.41
Electrolyzer Efficiency	13.11	27.96	Willingness Rate	7.44	29.83
Fuel Cell Efficiency	31.02	105.45	Electrolyzer Size	-28.50	-25.57

The sensitivity analysis conducted in the study explores the impact of various parameters on the optimization results of the FCEV2G system. There are many parameters affecting the optimization result, including market hydrogen cost, onsite hydrogen storage maximum capacity, electrolyzer efficiency, fuel cell efficiency, number of parking spots for participating FCEVs, market penetration rate of FCEVs to trucks, willingness of participating truck drivers, and input capacity of the onsite electrolyzer. It's important to note that while some parameters, such as market hydrogen cost or the efficiency of components, directly impact costs and revenue, others, like the willingness of participating truck drivers, affect more of the capacity of the system, thus indirectly influencing profitability. For each parameter, it was altered -50%, -25%, 25%, and 50% from the base case scenario. Because the site cost is not concerned by the optimization algorithm but becomes different by adjusting some of the parameters, it was added to the optimized profit to obtain the net profit after the optimization. The primary objective of the sensitivity analysis is to understand how changes in these parameters affect the profitability and performance of the FCEV2G system. It allows for an exploration of how different scenarios and parameter adjustments may impact the system's net profit and other key outcomes.

The variations from the base case for changing each parameter are shown in Figure 3-19, and the sensitivities of net profit to different parameters are quantitatively reported in Table 3-2. Every case in 2019 is shown to generate negative net profit, which suggests that the FCEV2G system is not profitable under the circumstances of electricity price in 2019. In contrast, most cases in 2022 offer a positive net profit, which can be explained by the higher electricity price and its volatility in 2022 compared to 2019 as discussed in Section 3.7.1. Higher electricity prices and increased price volatility enhance the profitability of FCEV2G. If this trend of higher electricity price and its volatility continues as predicted in Section 3.7.1, the profit is expected to increase in the future years.

Market hydrogen cost has a significant influence on net profit. In 2019, the variation in net profit caused by changes in market hydrogen cost is relatively smaller, with a range of 31k USD in 2019 between the lowest and highest variations. In 2022, the impact of market hydrogen cost is much more substantial, leading to a wider range of 200k USD. This difference can be attributed to the higher electricity prices in 2022 that make using market hydrogen more profitable and also increase the profit by lowering market hydrogen prices. This also corresponds to the finding that market hydrogen is responsible for a larger proportion of total hydrogen use in 2022. Fuel cell efficiency is identified as one of the most determining factors impacting net profit. It plays such a crucial role likely because hydrogen can only be consumed in fuel cells while it can be produced in two ways.

Overall, these observations emphasize the sensitivity of the FCEV2G system's profitability to various parameters and market conditions. The analysis underscores the dynamic nature of the system's performance and its responsiveness to changes in parameters, particularly in the context of evolving electricity prices and market conditions. It also underscores the critical role of market hydrogen cost and fuel cell efficiency in shaping the economic viability of the FCEV2G system, highlighting the importance of improving the efficiency of fuel cell technology and reducing market hydrogen cost.

3.9.1. Sensitivity of Net Profit to Component Efficiency

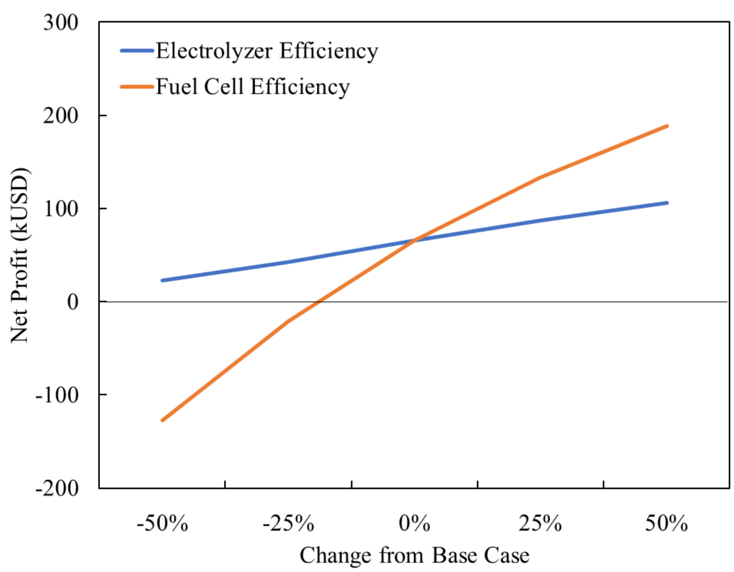

Figure 3-20 Net Profit of Scenarios where Electrolyzer and Fuel Cell Efficiencies are Changed -50%, -25%, 0%, 25%, and 50% from Base Case

The study examines the impact of varying the efficiencies of the electrolyzer and fuel cells on the net profit of the FCEV2G system. These efficiencies have significant implications for system performance and profitability. The electrolyzer is responsible for on-site hydrogen production and its efficiency directly affects the energy loss during hydrogen production. According to the International Renewable Energy Agency (IRENA), the typical efficiency of an electrolyzer running at nominal capacity is 65% and is expected to rise to 76% in 2050 [119]. In addition, electrolyzer efficiency varies by different models, ranging from 56% of Proton's PEMFC, to 73% of Stuart's and Norsk Hydro's bipolar alkaline systems [109], to 84% of Sunfire's high-temperature electrolyzer [120]. However, electrolyzer efficiency may fall as a result of not running at the optimal capacity, overtime decay, frequent turning on/off, etc. In this study, electrolyzer efficiency is set to 30%, 45%, 60%, 75%, 90% to reflect the different possible scenarios of lower and higher efficiency. One the other hand, fuel cells are the primary component responsible for converting hydrogen into electricity, and their efficiency affects the energy loss during electricity generation. Fuel cell efficiency varies from 40% of Phosphoric Acid Fuel Cell (PAFC) to 50% of Molten Carbonate (MCFC), to 60% of PEMFC, Solid Oxide Fuel Cell (SOFC), and Alkaline Fuel Cell (AFC) [108]. Fuel cell efficiency is set to 25%, 37.5%, 50%, 62.5%, 75% to reflect the current situation, the potential future improvement, and possible occasions when they run at non-optimal conditions.

Figure 3-20 shows that both efficiencies have significant impacts on the net profit, of which fuel cell efficiency has a larger impact. When increasing the electrolyzer efficiency from 30% to 90%, annual net profit increases from 22k USD to 106k USD, nearly increased 5-fold. When increasing fuel cell efficiency from 25% to 75%, annual net profit increases from -188k USD to 128k USD, changing from large deficit to large positive revenue. Efficiency of fuel cells has a higher impact on the net profit compared to the electrolyzer efficiency, which is because the fuel cells are the only hydrogen-to-electricity component while the electrolyzer and purchasing market hydrogen are both ways of obtaining hydrogen. This indicates that high fuel cell efficiency is essential to FCEV2G profitability and inefficient fuel cell operation increases the possibility of going into a deficit. Therefore, certain measures should be taken such as selecting FCEVs with high-efficiency fuel cells and optimizing the hydrogen/oxygen ratio to ensure its optimal efficiency [121].

3.9.2. Sensitivity of Net Profit to Component Size

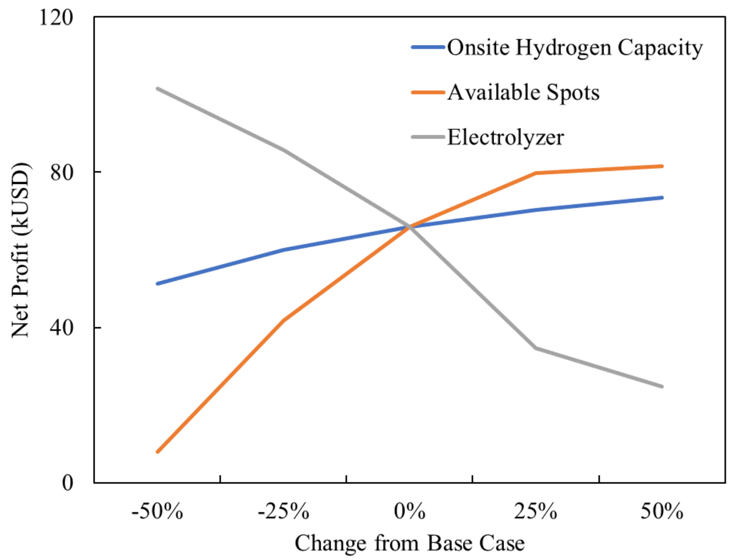

Figure 3-21 Net Profit of Scenarios where Onsite Hydrogen Storage Capacity, Available Parking Spots for Participating FCEVs, and Size of Onsite Electrolyzer are Changed -50%, -25%, 0%, 25%, and 50% from Base Case

The analysis of the impact of different key component sizes on the net profit of the FCEV2G station provides valuable insights into how these components influence the overall profitability and cost-effectiveness of the system. These components include the storage capacity of the onsite hydrogen tank (onsite hydrogen capacity in short), the number of available spots for FCEVs (available spots in short), and the size of the onsite electrolyzer (electrolyzer size in short).

Higher onsite hydrogen capacity allows more hydrogen to be stored at the same time and facilitates energy transfer between peak and off-peak hours. Increasing onsite hydrogen capacity from -50% to 50% from the base case raises the net profit from 75k USD to 99k USD by 32%. Hydrogen storage is a relatively cheaper component compared to the electrolyzer and dispensers as shown in Figure 3-17, and the additional investment is justified by the increased profitability. However, it is essential to consider space availability and safety requirements before expanding the onsite hydrogen storage capacity.

Increasing the number of available spots for FCEVs enables more vehicles to participate in FCEV2G simultaneously, thereby increasing the total fuel cell capacity; but in the meantime, more parking spots require more dispensers to fuel hydrogen into FCEVs. When available spots increase from 4 to 12, the annual levelized cost on them also increases 3-fold from 30780 USD to 29314 USD, while it also leads to a more than 10-fold improvement on net profit, from 8k USD to 82k USD. This suggests that accommodating more FCEVs can substantially enhance the profitability of the FCEV2G station.

A larger electrolyzer increases the ability to produce cheap hydrogen during off-peak hours, but also increases the CAPEX and OPEX on the most expensive component as per Figure 3-17. Figure 3-21 shows that within the range of -50% to 50% from the base case, the increasing cost on the electrolyzer outruns the increasing profit brought by it. This can be attributed to the high cost of the electrolyzer and its low capacity factor, 0.12 in the 2019 base case and 0.18 in the 2022 base case. However, this is not to say that the onsite electrolyzer is not useful for the FCEV2G station and the hydrogen supply should be solely from the market. Market hydrogen in real circumstances may not be always available, due to the demand for fueling or potential delivery disruptions, so the onsite electrolyzer is essential for securing a constant hydrogen supply.

These findings emphasize the importance of optimizing the sizes of key components within the FCEV2G system to achieve the highest level of profitability and cost-effectiveness. The trade-offs between capital investment, operating costs, and potential profit should guide decisions regarding the sizes of components. Furthermore, these results highlight the relevance of site-specific conditions to other factors, such as market dynamics and available resources, when determining the optimal configurations for FCEV2G stations.

3.9.3. Sensitivity of Net Profit to Market Hydrogen Cost

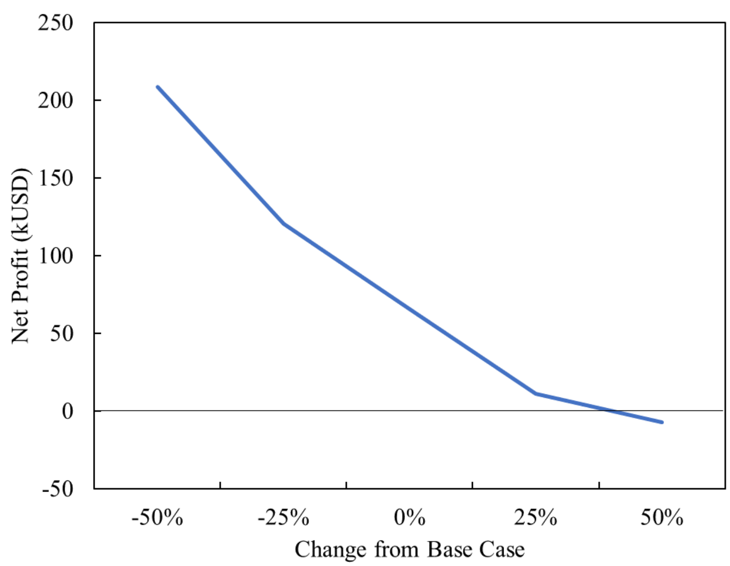

Figure 3-22 Net Profit of Scenarios where Market Hydrogen Price is Changed -50%, -25%, 0%, 25%, and 50% from Base Case

Market hydrogen price is a very important factor in the operation optimization since it directly affects when and how much grid hydrogen should be produced. It also decides the grid electricity price threshold of when using hydrogen is lucrative and to what extent it is. The base case market hydrogen price is 5 USD/kg, including 3 USD/kg on production and 2 USD/kg on delivery and processing, as shown in Table 2-5. The clean market hydrogen production cost varies with different clean electricity price and electrolyzer capacity factor. This cost becomes higher with reduced clean electricity price and elevated electrolyzer capacity factor and vice versa. The delivery and processing cost varies with different delivery methods, scales, and distances. Overall, longer distances and smaller delivery scales raise costs. In addition, liquid delivery is more expensive than gaseous delivery, and pipeline delivery is cheaper than the other two but only for large scales of hydrogen delivery. The total market hydrogen cost is set to 2.5, 3.75, 5, 6.25, 7.5 USD/kg to investigate its effect on the net profit.

Figure 3-22 shows the net profit at different market hydrogen cost when other parameters remain the same. When the market hydrogen price is halved from the base case to 2.5 USD/kg, the net profit experiences a substantial increase from 64k USD to 208k USD, indicating a more than 3-fold improvement in profitability. Furthermore, when the market hydrogen price rises by a half to 7.5 USD/kg, the FCEV2G station comes to a deficit of 7k USD after including the site cost. This result emphasizes the sensitivity of the FCEV2G profitability toward higher hydrogen prices and the potential for a financial loss when hydrogen costs are elevated. These findings underscore the importance of a cost-competitive hydrogen market for the economic success of FCEV2G. Market dynamics and future developments in the hydrogen industry will play a pivotal role in determining the financial feasibility of FCEV2G stations. More efficient clean hydrogen production, transportation, and a larger hydrogen market scale will make FCEV2G more lucrative.

3.9.4. Sensitivity of Net Profit to Penetration and Willingness Rate

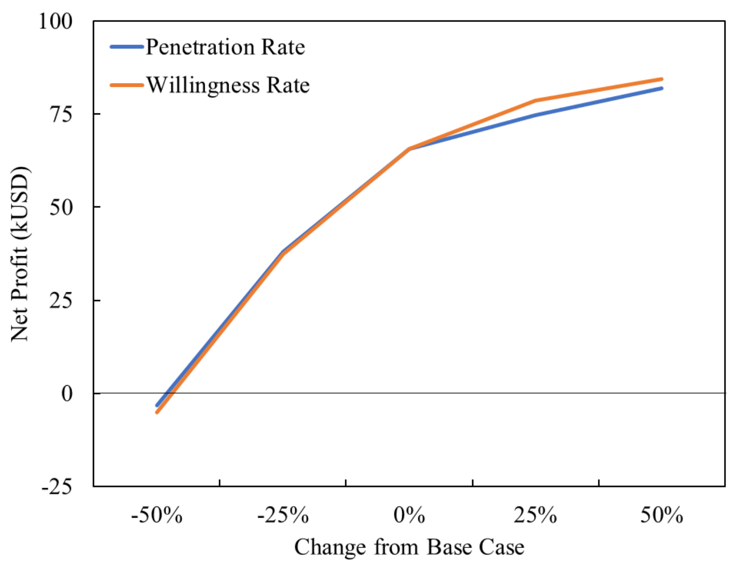

Figure 3-23 Net Profit of Scenarios where FCEV Market Penetration Rate and Participating Willingness Rate is Changed -50%, -25%, 0%, 25%, and 50% from Base Case

Figure 3-23 shows the net profit when the FCEV market penetration rate and participating willingness rate are adjusted -50%, -25%, 0%, 25%, and 50% from the base case. The FCEV market penetration rate refers to the percentage of FCEVs among all trucks. It is set at 6% in this study, as it is projected to be around 6% in 2030 [110]. However, note that this number may be different in different years or in other estimates of different optimism toward FCEV market acceptance. Willingness rate is the measurement of how many people will choose to participate in the FCEV2G and contribute their FCEVs to the station. It is set at 0.6 in the base case but adjusted to different values for an investigation into how it impacts the profitability of FCEV2G. They are shown to have very similar impacts on the optimization result. Higher penetration and willingness rate increase the profit by providing the FCEV2G with more available fuel cells for generating electricity. Nonetheless, this increasing trend slows with increasing penetration and willingness rate, likely because of the constraints of other components such as available spots and onsite hydrogen production volume. A high penetration rate or high willingness rate is essential to the profitability, and low values of them result in a deficit as shown in Figure 3-23 when they are both -50% from the base case. Overall, a high FCEV market penetration rate and a high willingness rate are essential for the profitability of the FCEV2G station. These results highlight the role of FCEV fleet size and market acceptance in determining the economic viability of FCEV2G stations.

3.10. Electrolyzer Sizing in Revenue Optimization and Grid Hydrogen Price

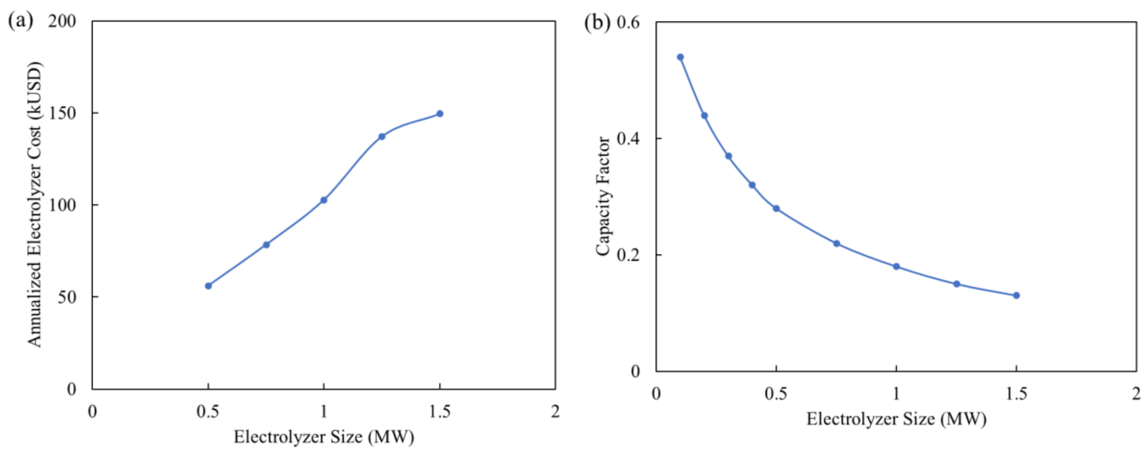

Figure 3-24 (a) Annualized Cost and (b) Capacity Factor of Onsite Electrolyzer of Different Sizes

Figure 3-21 shows that adopting a larger onsite electrolyzer can lead to a decreased profitability of the FCEV2G station when its input capacity is within the range of 0.5 MW to 1.5 MW. This is a result of high electrolyzer cost and limited low-price hours for grid electricity. Electrolyzer cost is shown in Figure 3-24a to be almost linearly ascending with increasing size. Larger hydrogen production capacity requires an electrolyzer to have more stacks, mechanical, and electrical equipment, in addition to a constant cost on engineering and design. Increasing the electrolyzer size also decreases its capacity factor, as shown in Figure 3-24b. The capacity factor is 0.54 when the input capacity is 0.1 MW and shrinks to 0.14 when the input capacity increases to 1.5 MW. A lower capacity factor means the electrolyzer stays idle for a large amount of time which makes more of the constant annualized CAPEX and OPEX of the electrolyzer fall on the levelized cost of every unit of produced hydrogen. This reverse relation between the electrolyzer size and the capacity factor can be explained by that a larger size enables the electrolyzer to operate more during peak hours but leave hours when prices are relatively high unutilized, which is more profiting when not considering the electrolyzer CAPEX and OPEX. Overall, this analysis suggests that careful consideration is required when sizing the onsite electrolyzer for an FCEV2G station. While larger electrolyzers have the potential to produce more hydrogen, it's essential to balance the increased capacity with the associated CAPEX and OPEX, as well as the station's ability to utilize the electrolyzer efficiently during peak hours. The optimal electrolyzer size may vary depending on specific factors such as electricity price dynamics, hydrogen demand, and the station's overall configuration.

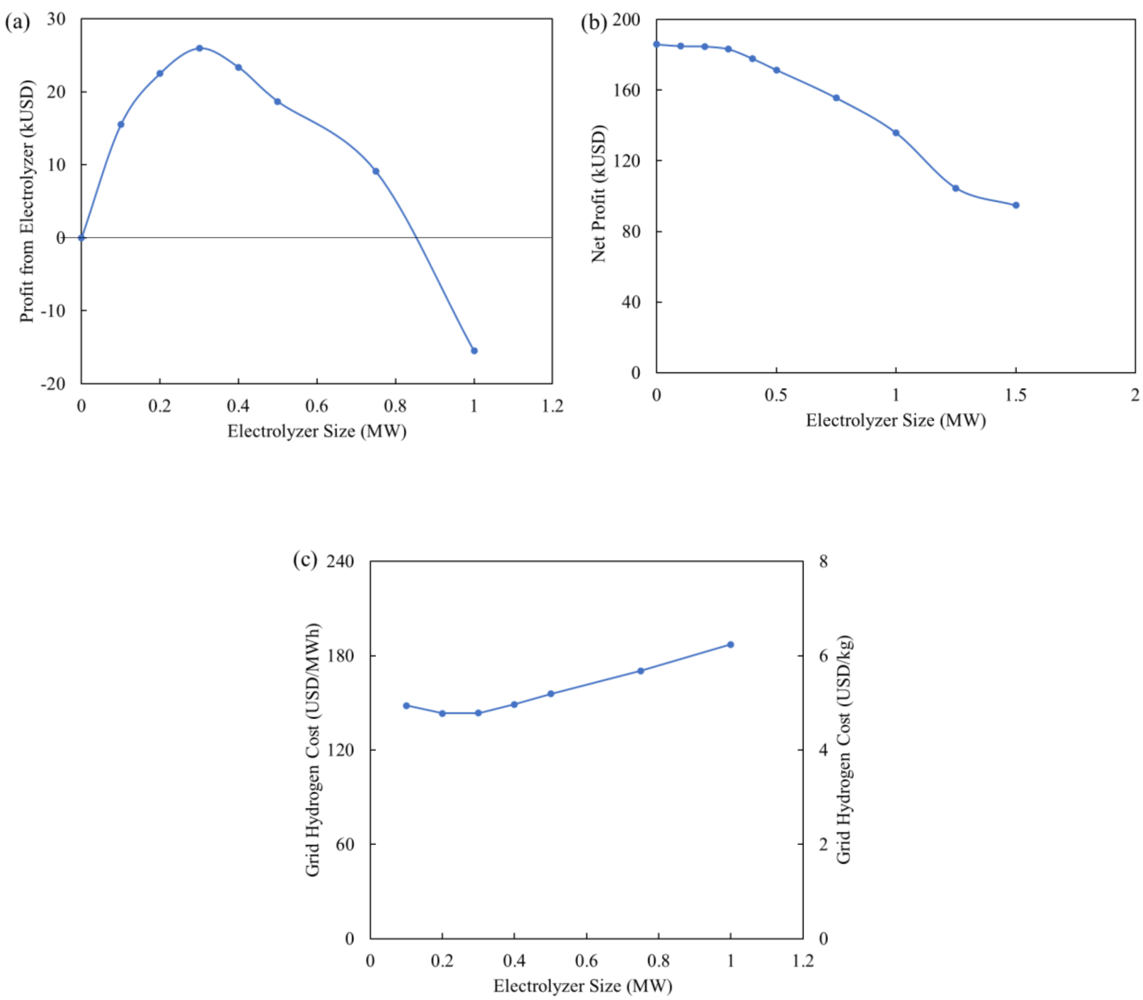

Figure 3-25 (a) Profit from the Onsite Electrolyzer, (b) Total Net profit, and (c) Levelized Price of Grid Hydrogen versus Different Electrolyzer Sizes

Figure 3-25a shows the profit from the electrolyzer at each different size, which is calculated by subtracting the electrolyzer cost and electricity cost from the profit of selling grid hydrogen in each scenario. The optimal size is found to be 0.3 MW when the profit from the electrolyzer reaches 23k USD. However, the grid hydrogen in this case only accounts for 29.77% of total hydrogen use, in contrast to 43.41% of total hydrogen use in the base case. When the size is larger than 1 MW, the cost on the electrolyzer exceeds the grid hydrogen sales and total profit from the electrolyzer becomes negative. Even though the profit from the electrolyzer has a maximum at 0.3 MW, increasing the onsite electrolyzer size still decreases total profit, as shown in Figure 3-25b. This is likely because even within the range of 0 to 0.3 MW, high grid hydrogen usage decreases market hydrogen uses which offsets the higher profit from selling grid hydrogen. Figure 3-25c shows the grid hydrogen price for different electrolyzer sizes, which has the reversed trend of profit from electrolyzer. It reaches the lowest, 143 USD/MWh (4.77 USD/kg), at 0.2 MW and 0.3 MW, and continues to rise with increasing electrolyzer size. It is essential to strike a balance between hydrogen production, cost-efficiency, and the utilization of grid and market hydrogen. The specific optimal size may vary depending on various factors, including electricity price dynamics, hydrogen demand, and the station's configuration.

3.11. Carbon Reduction Optimization in Alberta

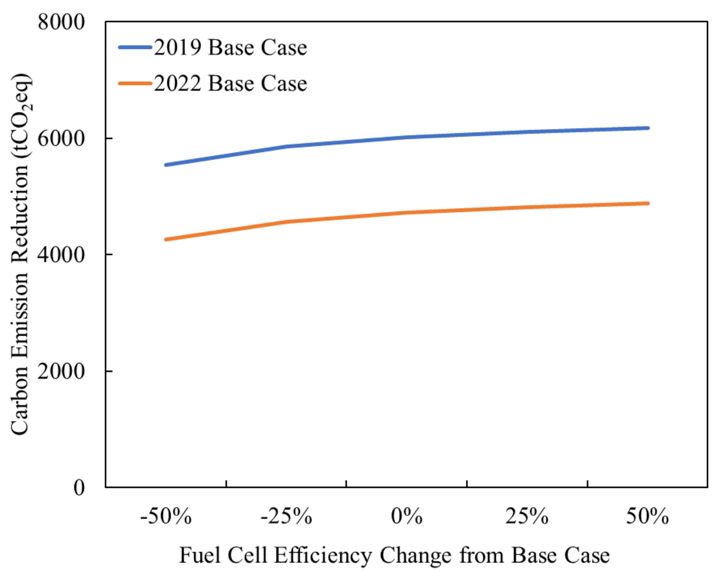

Figure 3-26 Optimized Carbon Reduction versus Different Fuel Cell Efficiency in Alberta in 2019 and 2022

Optimization on achieving reducing the maximum amount of carbon emissions is also performed, the result of which is strongly dependent on the electricity supply and carbon intensity in the two years. The optimization for maximum carbon emission reduction results in the exclusive use of market hydrogen because the stable carbon intensity of grid electricity in Alberta cannot overcome the efficiency losses associated with the electrolyzer and fuel cells, as discussed in Section 3.7.2. As a result, changing the electrolyzer efficiency, electrolyzer size, or onsite grid hydrogen storage capacity have no impact on the result of optimizing carbon emission reduction.

The optimal carbon reduction is 6011 tCO_2eq in the 2019 base case and 4720 tCO_2eq in the 2022 base case. Because all hydrogen is market hydrogen with constant carbon intensity, the difference between results of different years is primarily due to the declining carbon intensity of the Albertan electricity, which can be attributed to the expansion of solar power and phasing-out of coal power plants, as discussed in Section 3.7.2.

A sensitivity analysis is also performed to assess the impact of different parameters on carbon emission reduction. Changing the parameters on the grid hydrogen pathway has no impact because no grid hydrogen is used. Changing the parameters associated with the FCEVs and traffic including available spots, FCEV market penetration rate, and willingness rate, has a similar effect discussed in Section 3.9.2 and 3.9.4. The optimized carbon reduction in the 2019 and 2022 with different fuel cell efficiency is shown in Figure 3-26. The sensitivity of the optimization results toward fuel cell efficiency is 0.11 in 2019 and 0.15 in 2022. This means increasing the fuel cell efficiency has a rather low impact on carbon emission reduction, which is due to the fact that the carbon intensity of market hydrogen is already very low (20 $kgCO_2eq/MWh$) compared to grid electricity in Alberta (around 550 $kgCO_2eq/MWh$ in 2019 and 440 $kgCO_2eq/MWh$ in 2022).

In summary, the potential for carbon emission reduction through FCEV2G optimization is highly dependent on the carbon intensity of the electricity supply. When grid electricity has a stable carbon intensity and cannot compete with the efficiency losses of the electrolyzer and fuel cells, the optimization relies on market hydrogen. The low carbon intensity of market hydrogen plays a crucial role in achieving substantial carbon emission reductions. Therefore, the effectiveness of carbon reduction through FCEV2G stations is closely linked to the broader decarbonization efforts within the electricity generation sector and the development of mass clean hydrogen production.

Chapter 4. Optimization Using Ontario as a Case Study

4.1. Chapter Introduction

Ontario has the largest economy in Canada, accounting for 38% if the national GDP of Canada, and its manufacturing sector makes up for 46% of the total manufacturing GDP of Canada [114]. Ontario is also the most populous Canadian province, with 14.22 million permanent residents recorded in 2022 [122]. The large economy and population require a massive amount of electricity supply, which amounts to about 1.5 times that in Alberta. Due to the abundant hydro and wind power as well as several nuclear power plants, the electricity supply in Ontario is relatively clean and diverse. Highway 401 in Ontario has a large traffic volume of trucks and is identified by Hydrogen Business Council of Canada as the first adopter of hydrogen technology. [123] Results presented in this chapter were obtained using the same methodology as described in 3.5.

4.2. Electricity Price in Ontario

4.2.1. Electricity Price in Ontario

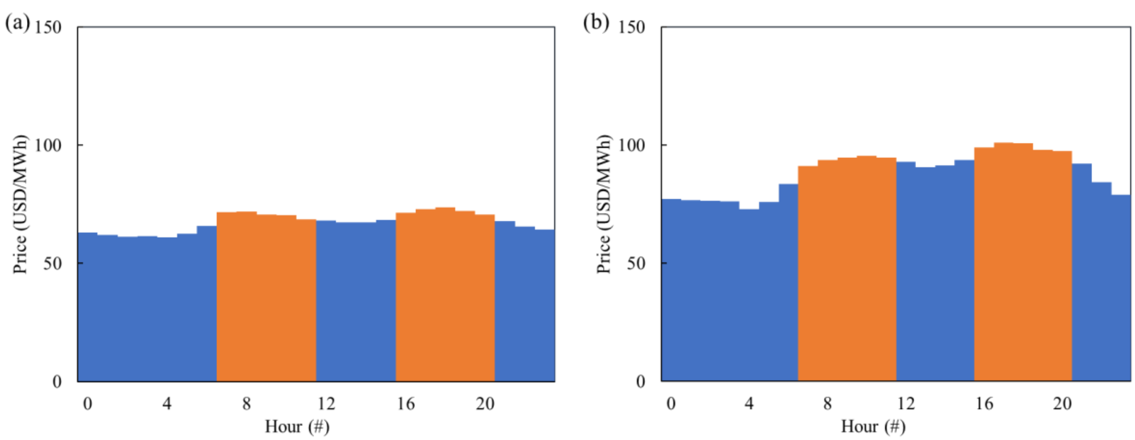

Figure 4-1 Yearly Average Grid Electricity Price at Each Hour of the Day (a) in 2019 and (b) in 2022

Figure 4-1 provides a comparison of the yearly average grid electricity prices at different hours of the day in Ontario for 2019 and 2022. The analysis reveals the following observations regarding electricity prices in Ontario. First, the electricity rate is notably lower and more stable compared to Alberta. The highest average price in Ontario was 74 USD/MWh in 2019 and 101 USD/MWh in 2022, which are significantly lower than 63 USD/MWh in 2019 and 211 USD/MWh in 2022 in Alberta. Second, similar to Alberta, Ontario experiences peak prices during the day. The two peak price periods also coincide with the rush hours highlighted in orange in Figure 4-1. In addition, the price increase from 2019 and 2022 also resembles that in Alberta, which suggests a general upward trend in electricity prices over this period in both provinces. Despite the similarity between the electricity prices in the two provinces, the relative affordability and stability of the grid electricity in Ontario, make it less easy to create profit in Ontario. The price gap between off-peak and peak electricity is not always large enough to offset the costs associated with the efficiency loss of the electrolyzer, fuel cells, and the FCEV2G site.

4.2.2. Grid Electricity Supply and Carbon Intensity in Ontario

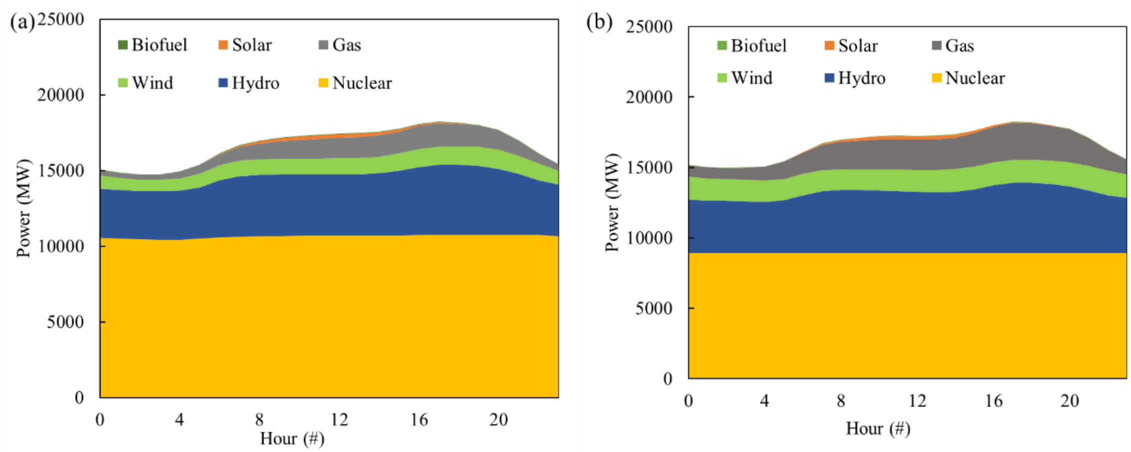

Figure 4-2 Supply Breakdown on Each Type of Power Generation in Ontario (a) in 2019 and (b) in 2022

Figure 4-2 shows the grid power breakdown in each type of power supply in 2019 and 2022, demonstrated as yearly average for each hour of the day. The grid energy source in Ontario is shown to be characterized by a more diverse range of energy sources compared to Alberta: nuclear, hydro, wind, and gas all have significant contributions to grid power supply in Ontario. Nuclear power is known for providing constant output and it plays a vital role in Ontario's energy mix, serving as the primary source for base load. In 2019, nuclear power contributed 64% of the total power supply, but this share declined to 53% in 2022. As for renewable energy sources, including hydro, wind, and solar, they also contribute substantially to the grid supply in Ontario. Gas is the only type of fossil fuel used in Ontario for power generation, and the peak supply hours around 7:00 and 17:00 are primarily supported by increased gas power generation, followed by increased hydro output. Even though the total power supply only increased by 1.6% between the two years, and gas power generation increased by 55%, probably to fill the gap caused by the 16% shrinking of the nuclear power supply. The increased reliance on gas power generation in response to declining nuclear output underscores the need for adaptable energy strategies in the face of changing energy supply dynamics.

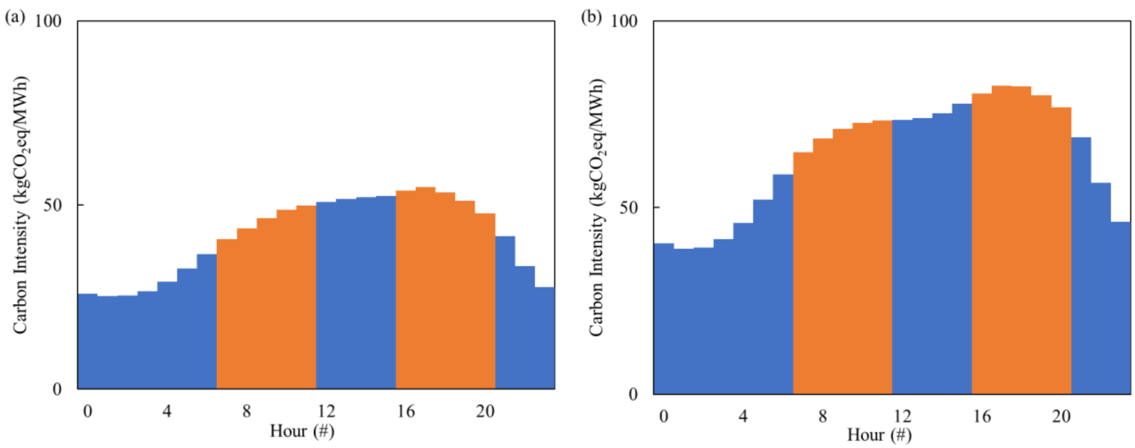

Figure 4-3 Yearly Average Grid Electricity Carbon Intensity at Each Hour in the Day in Ontario (a) in 2019 and (b) in 2022 (Rush Hours Highlighted in Orange)

Figure 4-3 highlights the significant variations in grid hydrogen carbon intensity in Ontario, which is driven by the diverse power supply and the daily operational change of different sources. The significant difference of power supply in Albert and Ontario results in distinct carbon intensity profiles in the two provinces. Because the base load is chiefly from nuclear power and peak load from gas power, the difference of carbon intensity during peak and off-peak hours is more significant than that in Alberta: The highest carbon intensity is approximately twice as high as the lowest carbon intensity in both years. Average carbon intensity at each hour increased from 42 $kgCO_2eq/MWh$ in 2019 to 64 $kgCO_2eq/MWh$ in 2022, by 52%. The increase in average carbon intensity is attributed to a shift in the power generation mix, specifically the decreased nuclear power supply and increased gas power supply. In addition, rush hours are shown to largely coincide with the peak carbon intensity hours, which creates an opportunity for FCEVs to contribute to the reduction of grid carbon intensity during these high-demand periods.

4.3. Revenue Optimization in Ontario

The optimization study conducted in Ontario with the aim of maximizing revenue has yielded results that fall short of covering the site cost, which has an annualized value of 172,719 USD. The revenue before considering the site cost is 5392 USD in the 2019 base case and 7194 USD in the 2022 base case, both below the threshold for reaching profitability. A sensitivity analysis similar to the one in Section 3.9 is also performed by using the data in Ontario, but the results are all not high enough to cover the site cost. The limited revenue-generating potential in Ontario is primarily because of the presence of affordable and stable electricity prices as discussed in Section 4.2. The low price variation makes it difficult to offset the efficiency loss associated with the production and consumption of hydrogen. However, the profit is expected to increase in the future with better technology of fuel cells and clean hydrogen production.

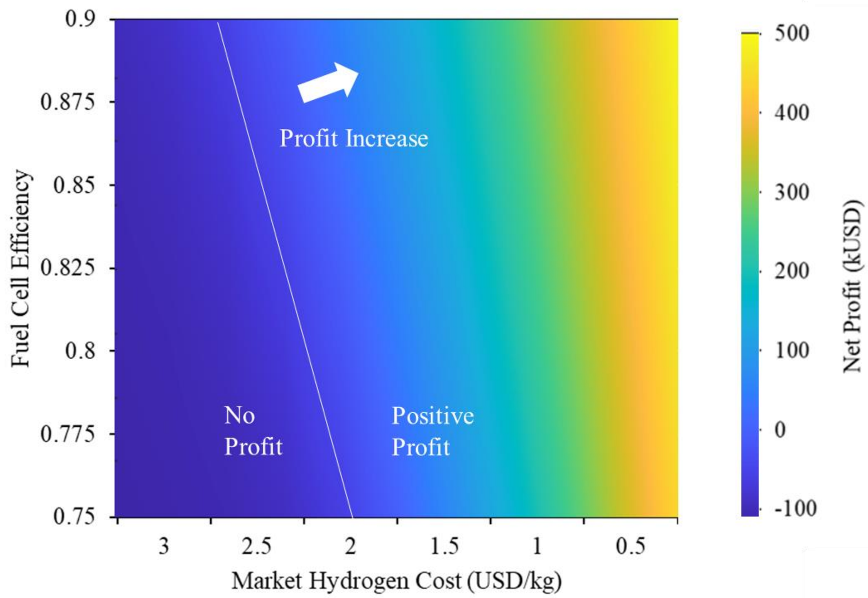

Figure 4-4 Operating Profit of Ontario Revenue Optimization with Different Fuel Cell Efficiency and Market Hydrogen Cost

The profitability of FCEV2G in Ontario is further investigated in scenarios with different fuel cell efficiency and market hydrogen cost to evaluate the prospects after future technological developments. The fuel cell efficiency ranges from 75% to 90%, and market hydrogen cost 3 USD/kg to 0.5 USD/kg. Grid hydrogen usage is excluded from the model because of the high CAPEX of the electrolyzer, and this makes the site cost only includes that of the dispensers, which is 61,561 USD/yr for 8 vehicle spots. The results shown in Figure 4-4 exhibits the optimized operating profits in different scenarios in different colors, where warmer colors represent higher profit and colder colors represent lower profit, which shows that higher fuel cell efficiency and lower market hydrogen cost can both lead to higher profit. The FCEV2G station is shown to become profitable after FCEV2G electricity cost, which is market hydrogen cost divided by fuel cell efficiency, is below 86 USD/MWh (2.87 USD/kg H_2). When market hydrogen cost is between 0.5 USD/kg and 2 USD/kg, increasing fuel cell efficiency has an apparently positive impact on the operating profit, but not when the cost is as low as 0.5 USD/kg. The highest net profit, at 90% fuel cell efficiency and 0.5 USD/kg market hydrogen cost, is 456k USD. In summary, although FCEV2G is not profitable in Ontario in the base case, but after technological advancements on fuel cell efficiency and hydrogen production cost, it can become lucrative in the future.

4.4. Carbon Emission Reduction Optimization in Ontario

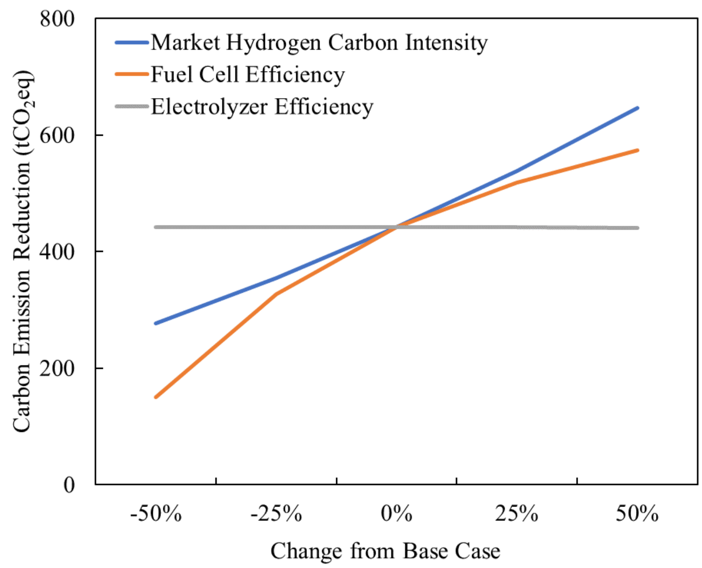

Figure 4-5 Carbon Emission Reduction Optimization Results in Ontario, 2022, at Different Market Hydrogen Carbon Intensity, Fuel Cell Efficiency, and Electrolyzer Efficiency that are -50%, -25%, 0%, 25%, and 50% from Base Case

The study examines the potential for reducing carbon emissions through the FCEV2G system in Ontario. Due to the relatively large carbon intensity variation of electricity in Ontario, this is a larger space of using cleaner electricity to produce hydrogen and feed it back to the grid compared to Albera. In the 2022 base case for Ontario, 213 t carbon emissions are reduced. This reduction is much smaller than the optimal carbon reduction in Alberta, primarily due to the electricity carbon intensity in Ontario is very low compared to that in Alberta, as discussed in Section 4.2.2.

The study then explores the impact of altering various parameters on the total carbon emission reduction in Ontario. However, only when changing market hydrogen carbon intensity, fuel cell efficiency, and electrolyzer efficiency, the result will change accordingly. This is because grid hydrogen is significantly more carbon-intensive than market hydrogen and hence only market hydrogen is used for maximizing carbon emission reduction unless gird hydrogen can be produced greener relative to the market hydrogen. Therefore, only parameters than can change the carbon intensity of using the two types of hydrogen have an impact on the result, and the result's sensitivity to them is shown in Figure 4-5. The carbon intensity of the market hydrogen has the largest impact on the optimization result and the trend appears to be nearly linear.

Overall, the analysis demonstrates that the FCEV2G system's ability to reduce carbon emissions in Ontario is highly sensitive to the carbon intensity of market hydrogen and fuel cell efficiency. Achieving the maximum carbon emission reduction in Ontario involves optimizing these parameters to use cleaner electricity and hydrogen sources effectively.

Chapter 5. Conclusion and Future Work

5.1. Conclusion

In this research, the grid electricity price and carbon emissions are analyzed before a mixed linear integer programming model is applied to optimize the monetary revenue and carbon emission reduction. The FCEV2G station considered in this research incorporates an onsite electrolyzer, onsite hydrogen storage, and dispensers for distributing hydrogen into FCEVs, which generate electricity and feed it back into the grid. In addition to the grid hydrogen, hydrogen supply can also be obtained from a market with abundant amounts of clean and stably priced hydrogen albeit incurring delivery cost. After establishing the model, the optimization is implemented in Ontario and Alberta, two of the Canadian provinces with the largest industry and electricity demand, and the data of 2019 and 2022 are utilized, representing different electricity market conditions.

The revenue optimization results in Alberta reveal a deficit of 82,946 USD in the 2019 base case, but a net profit of 65,616 USD in the 2022 base case. The primary cost of the FCEV2G station is on buying electricity and market hydrogen, followed by the site cost, with the electrolyzer cost being the most substantial. The reason of the significant difference in the profitability of the FCEV2G station in two different years is that the grid electricity price in Alberta was much higher and more unstable than that in 2019, and high grid electricity price and its volatility is the base of the profitability of any grid energy balancing technology. The profit is projected to increase in future scenarios, because Albertan electricity prices have been increasingly high and volatile in the past 7 years.

A sensitivity analysis of the impact of different parameters on the optimization results was also performed. Fuel cell efficiency and market hydrogen cost emerge as the most determining factors of generating profit, followed by the FCEV market penetration rate and participating willingness rate. On the other hand, due to the high cost of the electrolyzer, an increase in its size decreases the net profit. However, onsite electrolysis is still crucial in scenarios involving market hydrogen shortage or cost fluctuations.

Optimizing the monetary profit of FCEV2G can simultaneously reduce carbon emissions. By using market hydrogen produced from renewables, carbon emissions are decreased by 185 t in the 2022 base case. However, generating electricity using grid hydrogen has a higher carbon intensity than grid electricity because of the efficiency loss of the electrolyzer and fuel cells. As a result, the key to reducing carbon emissions is to use more clean market hydrogen in lieu of grid hydrogen.

The base case scenario in Ontario cannot yield positive net profit, due to the relatively stable and low-cost grid electricity in Ontario. However, the profit potential of FCEV2G may increase in the future with more efficient fuel cells and hydrogen production: by using the 2022 data, the FCEV2G station becomes profitable after market hydrogen cost divided by fuel cell efficiency is below 86 USD/MWh. On the carbon emission reduction front, the optimization in Ontario demonstrates that FCEV2G has the potential of lowering carbon emissions through the production of hydrogen using low-carbon intensity grid electricity and generating electricity using this cleaner hydrogen. A total amount of 442 t carbon emissions is reduced in the 2022 base case. It is also discovered that improving fuel cell efficiency and market hydrogen carbon intensity has a significant positive impact on emission reduction.

5.2. Prospects of Implementing FCEV2G in Alberta and Ontario

Although this study shows FCEV2G has a large potential of generating profits and reducing carbon emissions, the prospects of implementing FCEV2G are constrained by factors including technologies and infrastructure. First, the implementation of FCEV2G stations needs an existing hydrogen market, where hydrogen is mostly green hydrogen, which is most likely in Ontario which already has abundant nuclear and renewable energy output. If this hydrogen market grows to certain scales and allows hydrogen pipeline transportation, market hydrogen cost will reduce and profit of FCEV2G will increase. Second, a fleet of FCEVs on highways will be necessary, because FCEV2G uses the fuel cells in these vehicles to diminish the costs on purchasing FCs. In addition, technology of connecting fuel cells to the grid is a prerequisite, which can be transferred from existing technologies supplying electricity from BEVs to the grid.

The prospects of implementing FCEV2G are also constrained by the future change of energy supplies. First, in terms of the hydrogen market, the efficiency and scale of mass hydrogen production from renewable energy will significantly impact the prices and carbon intensities of the market hydrogen. Considering the fossil fuel abundance in Alberta, grey and blue hydrogen will have a significant market share at the beginning, so reducing carbon emissions in Alberta via FCEV2G needs prerequisites including more renewable power plants and high green hydrogen production. Second, the profitability of FCEV2G relies on the high level and instability of grid electricity prices. Therefore, FCEV2G is projected to be increasingly profitable in the future because electricity prices are expected to rise and become more unstable, a result of higher grid burdens from more battery electric vehicles, heat pumps, intermittent renewable power supply, and potential retirement of old nuclear power plants in Ontario. However, the profitability will decrease if electricity prices drop and stabilize due to other technology and policy changes. Last, FCEV2G is able to help reduce carbon emissions in Alberta, but this ability might diminish if more renewable energy appears and more coal power plants are phased out in Alberta.

In summary, the implementation of FCEV2G in the two provinces requires mature hydrogen markets and available V2G technologies, and its benefits vary with different future scenarios. The government can facilitate the market penetration of FCEVs and emergence of hydrogen markets which are necessary for FCEV2G.

5.3. Limitations of the Study and Recommendations of Future Work

This study uses MILP and historical data in Alberta and Ontario to analyze the economic and carbon reduction potential of FCEV2G. A number of limitations and possible future improvements are identified for helping build a more realistic model simulating its operation and bettering the understanding of FCEV2G.

(a) A combined model of sizing components and operational optimization may better examine the profitability of FCEV2G. The current model optimizes the operation with preset parameters including electrolyzer size, onsite hydrogen storage capacity, etc. This approach can obtain the optimal way of operation to generate the maximum revenue or emission reduction from an FCEV2G with a group of specific parameters but cannot find the best sizing of different components or the highest result of this best sizing. A model combining the sizing and operational optimizing can help fathom the whole potential of FCEV2G.

(b) A traffic prediction algorithm can provide more realistic data to the optimization model. The current model assumes several rates and applies them to historical traffic data at a certain location to estimate the number of FCEVs available to the FCEV2G station. However, this data cannot represent the total traffic situation beside a future FCEV2G station.

(c) A closer investigation into a potential FCEV2G station is needed. For now, the assumed FCEV2G station is only imaginary which represents the key features of FCEV2G but may lack some details in a realistic scenario. The fueling process, the connection between FCEVs with the grid, the electricity frequency management, and participation behaviors of FCEV drivers should all be considered in the future to better understand what a future FCEV2G would be like.

(d) This analysis only considers using hydrogen for energy generation/buffering purposes, but this hydrogen may also be used as vehicle fuel as well. In addition, hydrogen vehicle fuel will come into the economy before using hydrogen in energy generation/buffering, or FCEV2G in this study. Therefore, it would be interesting to analyze a case where hydrogen can be used as both vehicle fuel and energy buffer, the amounts and ratios of which would change over time. This potential improvement may provide a clearer timeline on when FCEV2G will become profitable and competitive.

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