Developing Models Using Game Theory for Analyzing the Interaction of Various Stakeholders in Energy Systems

by

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Examining Committee

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Author’s Declaration

This thesis consists of material all of which I authored or co-authored: see Statement of Contribution included in the 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.

Statement of Contributions

The body of this thesis is based on a combination of published work, work accepted for publication, and work currently under review. Various sections are adapted from the following list of publications:

Chapter 3

Haghi, E., Raahemifar, K., & Fowler, M. (2018). Investigating the effect of renewable energy incentives and hydrogen storage on advantages of stakeholders in a microgrid. Energy Policy, 113, 206-222.

I developed the modeling framework and carried out the simulation. I prepared all the results and wrote the final manuscript. Dr. Fowler and Dr. Raahemifar reviewed the manuscript.

Chapter 4

Haghi, E., Fowler, M., & Raahemifar, K. (2019). Co-benefit analysis of incentives for energy generation and storage systems; a multi-stakeholder perspective. International Journal of Hydrogen Energy, 44(19), 9643-9671.

I developed the modeling framework and carried out the simulation. I prepared all the results and wrote the final manuscript. Dr. Fowler and Dr. Raahemifar reviewed the manuscript.

Chapter 5

Haghi, E., Shamsi, H., Dimitrov, S., Fowler, M., & Raahemifar, K. Assessing the potential of fuel cell-powered and battery-powered forklifts for reducing GHG emissions using clean surplus power; a game theory approach. Accepted for publication in International Journal of Hydrogen Energy.

Dr. Dimitrov and I developed the modeling framework. Mr. Shamsi and I carried out the simulation. I prepared all the results and wrote the final manuscript. Dr. Dimitrov, Dr. Fowler, and Dr. Raahemifar reviewed the manuscript.

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I developed the modeling framework and carried out the simulation. Qinghao Kong helped with data gathering and structuring the paper. I prepared all the results and wrote the final manuscript. Dr. Qadrdan, Dr. Fowler, and Dr. Raahemifar reviewed the manuscript.

Chapter 6

Haghi, E., Qadrdan, M., Wu, J., Jenkins, N., Fowler, M., Raahemifar, K., An iterative approach for optimal decarbonization of electricity and heat supply systems, Submitted to Energy.

Dr. Qadrdan and I developed the modeling framework. Dr. Jenkins and Dr. Wu were advisors for model development and results generation. I prepared the simulation results and wrote the final manuscript. Dr. Qadrdan, Dr. Fowler, and Dr. Raahemifar reviewed the manuscript.

Abstract

Air pollution, global warming, climate change, and economic development are all reasons for governments around the world to incentivize the development of renewable energy generation technologies and plan for a transition toward a low-carbon economy. The development of renewable energy projects as well as the liberation in electricity systems has led to the emergence of multiple stakeholders in energy systems.

While the research focused on investigating the objective of a single stakeholder in an energy system is abundant in the literature, considering the objectives of all stakeholders in a multi-stakeholder model is a gap in the research. This thesis is aimed at developing a multilevel framework for modeling and analyzing the interaction of various stakeholders in energy systems. The models developed in this thesis are focused on investigating two areas: 1. The role of energy storage systems in Ontario and how they can be used to reduce GHG emissions in the province, and 2. Analyzing the interaction of the heat and electricity supply systems in Great Britain.

The contribution of this thesis is presented through four studies.

The objective of the first study is to investigate the effect and cost-efficiency of different renewable energy incentives and potential for wind and hydrogen energy systems to the perceived viability of a microgrid project from the prospective of different stakeholders, i.e., government, energy hub operator and energy consumer in the province of Ontario, Canada. Hourly simulation of a microgrid in which wind and/or hydrogen are produced is used for the analysis. Results show that using underground seasonal storage leads to the government paying less incentive per kg of CO_2 emission reduction as it lowers the levelized cost of hydrogen and provides a higher carbon emission reduction potential. Results of the first study also show that for the same incentive policy, incentivizing hydrogen production with grid electricity or a blend of wind power and grid electricity and producing hydrogen using wind power with underground hydrogen storage are more cost-efficient options for government than incentivizing wind power production. Regarding the renewable energy incentives, a combination of capital grant and FIT is shown to be a more cost-efficient incentive program for the government than FIT only programs. However, FIT programs are more effective for promoting the development of renewable energy technologies.

In the second study, the advantages of energy incentives for all the stakeholders in an energy system were analyzed in the context of a microgrid using a more comprehensive approach.

In the second study, the effect of health impacts from fossil fuel consumption and taxes collected from the energy hub operator and energy consumer are considered in the model. The stakeholders considered in the second study include the government, the energy hub operator, and the energy consumer. Two streams of energy incentives were compared in the second study: incentives for renewable energy generation technologies and incentives for energy storage technologies. The first stream aims to increase the share of renewable energies in the electricity system while the second stream aims the development of systems which use clean electricity to replace fossil fuels in other sectors of an energy system such as the transportation, residential and industrial sectors. The results of the analysis in the second study show that replacing fossil fuel-based electricity generation with wind and solar power is a less expensive way for the energy consumer to reduce GHG emissions (60 and 92 CAD per tonne of CO_{2e} for wind and solar, respectively) compared to investing on energy storage technologies (225 and 317 CAD per tonne of CO_{2e} for Power-to-Gas and battery-powered forklifts, respectively). However, considering the current Ontario's electricity mix, incentives for the Power-to-Gas and battery-powered technologies are less expensive ways to reduce emissions compared to replacing the grid with wind and solar power technologies (1479 and 2418 CAD per tonne of CO_{2e} for wind and solar, respectively). The analysis in the second study also shows that battery storage and hydrogen storage are complementary technologies for reducing GHG emissions in Ontario.

This third study aims at developing a game theory model for assessing the potential of fuel cell-powered and battery-powered forklifts for reducing GHG emissions in the province of Ontario, Canada. Two stakeholders are considered in the developed model: government and energy consumer, which is an industrial facility operating forklifts. The energy consumer, which is assumed to be an industrial facility, operates 150 diesel forklifts but has the option of replacing them with fuel cell-powered and battery-powered forklifts. The government can encourage this replacement by allocating a percentage of Ontario's surplus power to the energy consumer at a discounted price. The discount is assumed to be in the form of exempting the energy consumer from paying the global adjustment. As a result, the energy consumer only pays the hourly Ontario electricity price when discounted power is available. Discounted electricity will decrease the cost of operating battery-powered and fuel cell-powered forklifts for the energy consumer and will encourage the use of those technologies instead of diesel forklifts. The government has an

incentive to pursue such policy as the replacement of diesel forklifts with fuel cell-powered and battery-powered forklifts will reduce GHG emissions and subsequently, the social cost of carbon in the province. The results of the third study show that when the government does not allocate discounted power to the energy consumer, energy consumer does not reduce emissions and keeps using the 150 diesel forklifts. However, when the government provides 0.1% of Ontario's surplus power at each hour to the energy consumer at a discounted price, the energy consumer replaces 31 of diesel forklifts with battery-powered forklifts. When the percentage of discounted power is 0.6% of Ontario's surplus power at each hour, energy consumer replaces 91 of diesel forklifts with battery-powered forklifts and 54 of diesel forklifts with fuel cell-powered forklifts. A policy of discounting surplus power to encourage replacing diesel forklifts with battery-powered and fuel cell-powered forklifts is shown to benefit both stakeholders in the system. The third study also shows that the deployment of both fuel-cell powered and battery-powered forklifts is effective in reducing GHG emissions in Ontario when surplus clean power is available. Battery-powered forklifts are more cost-effective when lower levels of discounted power are available; however, with an increase in the level of available discounted power, fuel cell-powered forklifts become more cost-effective technologies compared to battery-powered forklifts.
The same methodology is also used for analyzing the potential of clean surplus power in Ontario to reduce GHG emissions in the residential sector.

In the fourth study, an iterative optimization model is developed to analyze the interaction of heat and electricity sectors at a national level in Great Britain. Independent mathematical models for optimizing the selection of technologies in heat and electricity supply systems are developed in the fourth study. The optimal mix of technologies for supplying electricity and heat were then calculated iteratively to take into account the interactions between the electricity and heat systems and their fragmented planning strategies. The capacity and operation of various technologies for electricity generation were optimized to supply electricity demand with a minimum annual cost. Then, the heat supply options were determined through minimization of the annualized cost of the heat supply system. Iterative optimization of electricity and heat was continued until an equilibrium was achieved. The results of the iterative approach were compared with a centralized optimization model in which heat and electricity problems are solved simultaneously.

Acknowledgments

Pursuing my doctorate at the University of Waterloo in Canada was a true privilege for me. I would like to thank my supervisors, Professor Michael Fowler and Professor Kaamran Raahemifar, for their support of my work, and caring for my professional development. I learned a lot from them and owe them a great deal for their support and help in the past few years.

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In the end I would like to thank my wife Sara, for her patience and support. Somehow she managed to bear with me during my Ph.D. I couldn't have done it without her.

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List of Symbols

g	Gram
kg	Kilogram
lb	Pound
kWh	Kilowatt hour
MWh	Megawatt hour
GWh	Gigawatt hour
TWh	Terawatt Hour
kW	Kilowatt
MW	Megawatt
GW	Gigawatt
th	Thermal
e	Electrical
hr	Hour
s	Second
m	Meter
m^3	Cubic meters
BTU	British Thermal Units
MMBtu	Million British Thermal Units
SCF	Standard Cubic Foot
€	Euro
$	Dollar
£	Pound sterling

List of Acronyms

GHG	Greenhouse Gasses
IESO	Independent Electricity system Operator
HOEP	Hourly Ontario Electricity Price
GA	Global Adjustment
CAD	Canadian Dollars
HHV	Higher Heating Value
FIT	Feed-In-Tariff
FIP	Feed-In-Premium
IRR	Internal Rate of Return
PBP	Payback Period
NPV	Net Present Value
DCF	Discounted Cash Flow
TGC	Tradable Green Certificates
REC	Renewable Energy Certificate
NM	Net Metering
NG	Natural Gas
HENG	Hydrogen-Enriched Natural Gas
R&D	Research and Development
LNG	Liquefied Natural Gas
SBG	Surplus Baseload Generation
ICE	Internal Combustion Engine
PV	Photovoltaics
IC	Investment Cost

GI	Government Incentives
O&M	Operation and Maintenance
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
CO	Carbon Monoxide
PMx	Particulate Matter
NOx	Nitrogen Oxide
SOx	Sulfur Oxide
SCF	Standard Cubic Foot
MIP	Mixed Integer Program
GAMS	General Algebraic Modeling System
FCV	Fuel Cell Vehicle
BEV	Battery Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
EV	Electric Vehicle
SCC	Social Cost of Carbon
CHP	Combined Heat and Power
FC	Fuel Cell
ASHP	Air Source Heat Pump
GSHP	Ground Source Heat Pump
CCGT	Combined-cycle Gas Turbine
OCGT	Open-Cycle Gas Turbine
CCS	Carbon Capture and Storage
GB	Great Britain

UK	The United Kingdom
US	The United States
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Heat
COP	Coefficient of Performance

1 Introduction

1.1 Motivation

The development of renewable energy projects and energy storage systems, as well as the liberalization of electricity systems, has led to the emergence of multiple stakeholders in energy systems. Not considering the advantages of all stakeholders in the planning of energy systems may lead to suboptimal Greenhouse Gas (GHG) emission reduction pathways.

While Ontario has been successful in phasing out coal power plants and the development of renewable energy generation capacity in recent years, such transition has caused challenges in the electricity system. Power export at low prices and curtailment of surplus clean power as well as rising electricity prices are some of these challenges. In that sense, analyzing the advantages of different stakeholders when renewable energy and energy storage programs are developed is of great importance.

Heat decarbonization is another transition in energy systems that has been investigated in this study. A favorite policy to decarbonize the electricity sector has been to replace fossil fuel-based electricity generation with renewable power in the past few years. For the heat and transportation sectors, however, electrification has been suggested as a pathway to reduce GHG emissions. Following such pathway will have significant effects on the electricity sector. The interaction of the heat and electricity sectors in a national scale is investigated in this work to analyze that effect.

This thesis starts with deterministic models for analyzing the interaction of stakeholders in a microgrid. Then optimization models are presented to analyze the objectives of stakeholders in microgrid energy systems. In the last study of this thesis, a framework for modeling the interaction of different energy sectors at a national scale is presented.

1.2 Ontario's electricity system

In this section of the thesis, an overview of the transition in Ontario's electricity systems and challenges Ontario has faced in recent years is discussed.

1.2.1 Ontario's electricity mix and generation capacity

Ontario's electricity system has experienced significant changes in recent years. The government of Ontario planned for the phase-out of coal power plants in the province by 2007 in 2004 [1].

The phase-out of coal electricity generation was completed in 2014 in Ontario [1]. Additionally and as part of the Green Energy and Green Economy Act, Ontario implemented a feed-in tariff (FIT) policy for the development of wind, solar, bioenergy, and hydropower electricity generation technologies in 2009 [1]. These policies have led to a change in Ontario's power generation capacity. Figure 1-1 shows the changes in Ontario's generation capacity from the opening of the electricity market in the province (2002) to 2019.

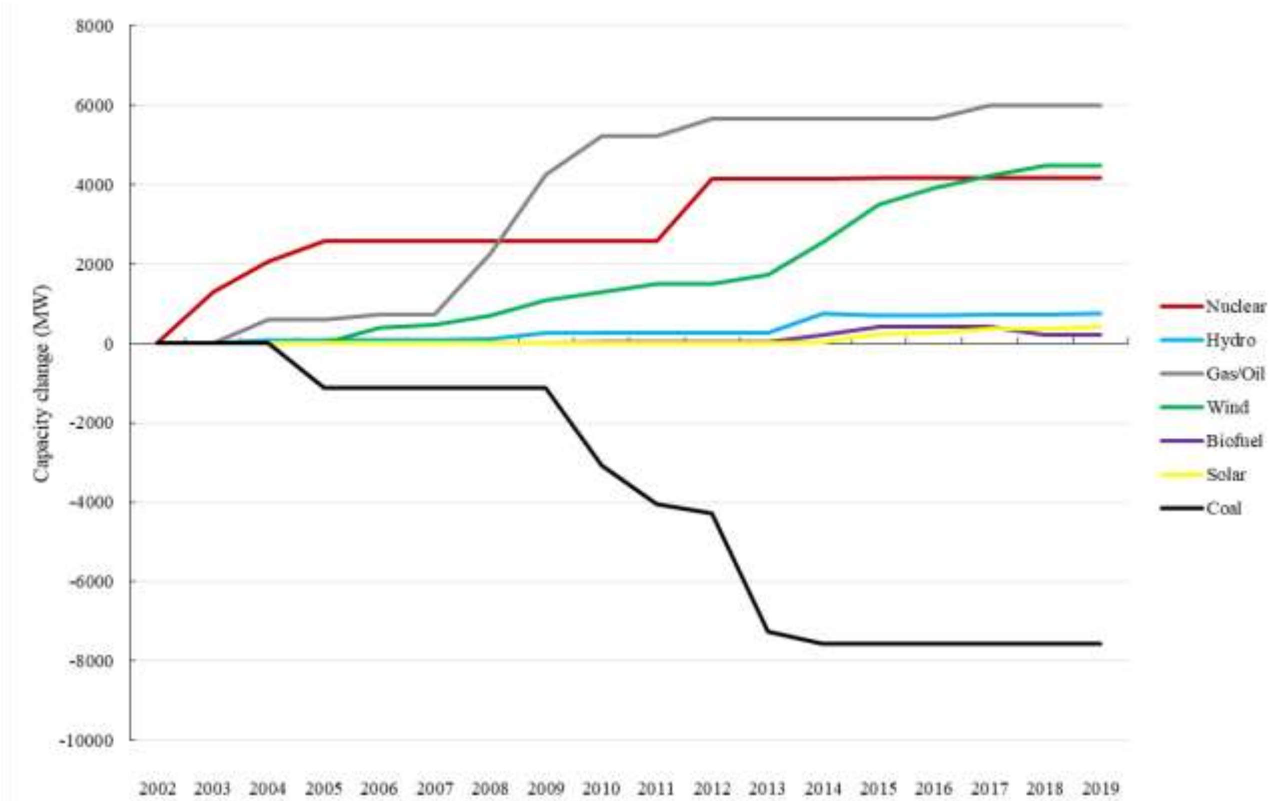


Figure 1-1. Change in Ontario's generation capacity from 2002 to 2019 [2]

As can be seen in Figure 1-1, wind, nuclear, and gas/oil power capacity has increased in Ontario while coal power generation capacity has dropped significantly as it was eventually phased out in 2014.

Figure 1-2 shows the current Ontario's transmission-connected electricity generation capacity based on the Independent Electricity System Operator's (IESO) Reliability Outlook released June 2019 [3].

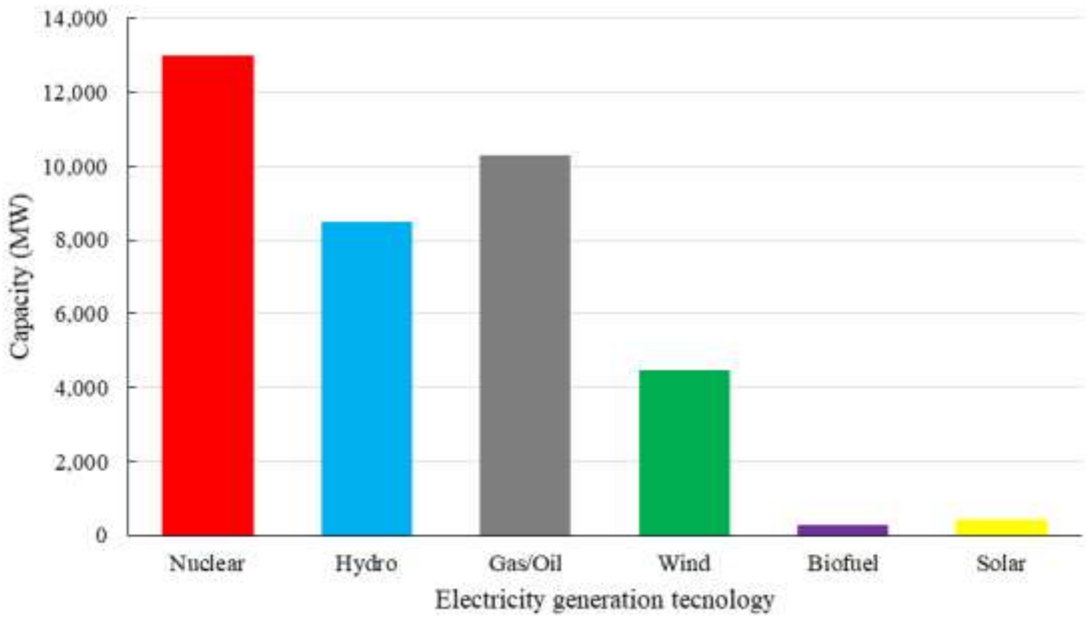


Figure 1-2. Current Ontario's transmission-connected electricity generation capacity [3]

Figure 1-3 shows Ontario's electricity generation mix in 2018. As can be seen in Figure 1-3, More than 93% of Ontario's electricity generation mix in 2018 was from emission-free resources.

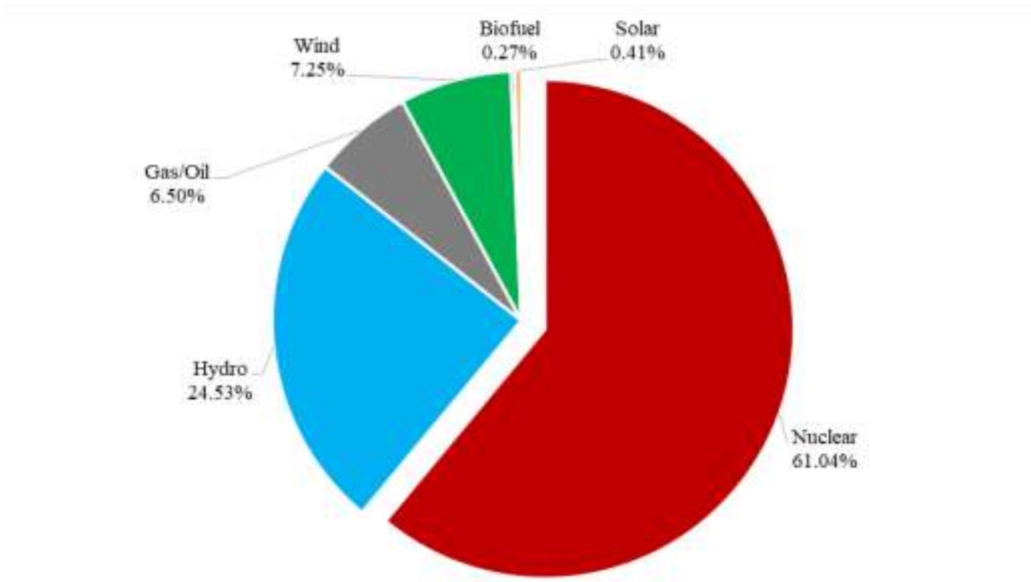


Figure 1-3. Ontario's electricity generation mix in 2018 [2]

These changes have led to a significant decrease in GHG emissions from the electricity sector in Ontario. Emissions from the electricity sector in Ontario dropped 67% from 2007 to 2013 while the emission from buildings dropped only 2% and emission from the transportation sector increased 2% in the same period [4].

1.2.2 Electricity price in Ontario

Hourly Ontario electricity price (HOEP) is the wholesale electricity price in Ontario which is determined by clearing the market by IESO. HOEP is affected by the supplied power and demand at each hour. Ontario has experienced a drop in HOEP in recent years. Figure 1-4 shows the yearly average HOEP from 2002 to 2017.

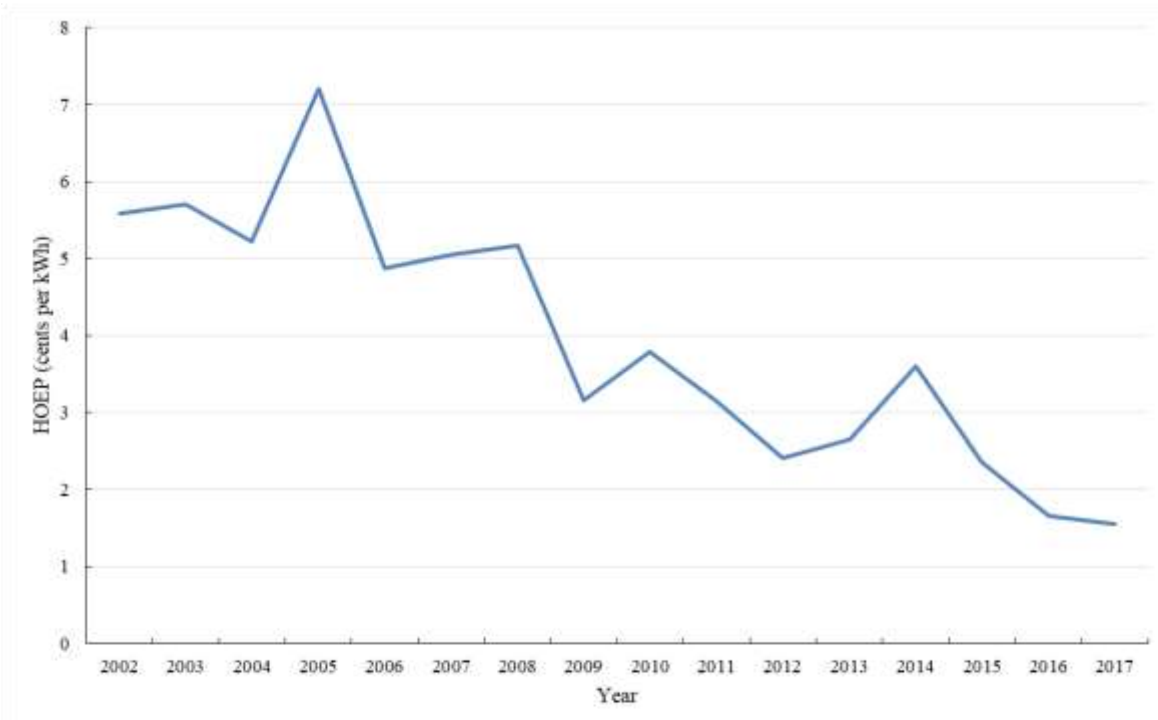


Figure 1-4. Yearly average HOEP from 2002 to 2017 [5]

As can be seen in Figure 1-4, HOEP has dropped 73% from 2002 to 2017. HOEP has decreased not only because of an increase in supply capacity but also because of a decrease in Ontario's electricity demand. From 2007 to 2018, Ontario's annual electricity demand dropped from 152 TWh to 137.4 TWh, a 10.6% decrease [6].

HOEP, however, is not the total commodity electricity cost paid by energy consumers in Ontario. Global adjustment (GA) is another part of the electricity price charged to developing new electricity infrastructure in Ontario, operate and maintain existing infrastructure, and paying for conservation and demand-side management initiatives in the province [7].

Contrary to the decrease in HOEP, GA has increased in recent years in Ontario. Figure 1-5 shows how GA has changed from 2011 to 2018. The values shown in Figure 1-5 have been calculated by averaging GA monthly values from 2011 to 2018.

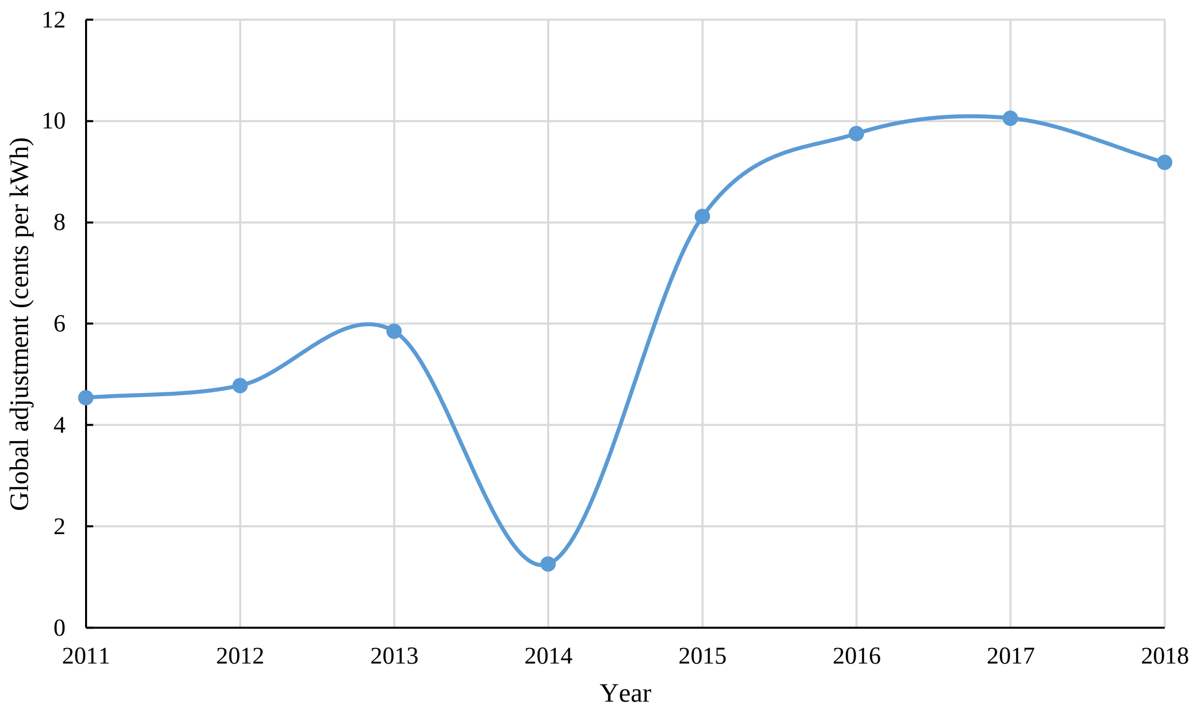


Figure 1-5. GA in Ontario from 2011 to 2018 [8]

As can be seen in Figure 1-5, Global adjustment has increased by 121% from 2011 to 2017, while HOEP has dropped 51% as can be seen in Figure 1-4.

Figure 1-6 shows HOEP plus GA in Ontario from 2011 to 2017. As can be seen in Figure 1-6, the decrease in HOEP has been offset with GA increase with a total higher electricity price.

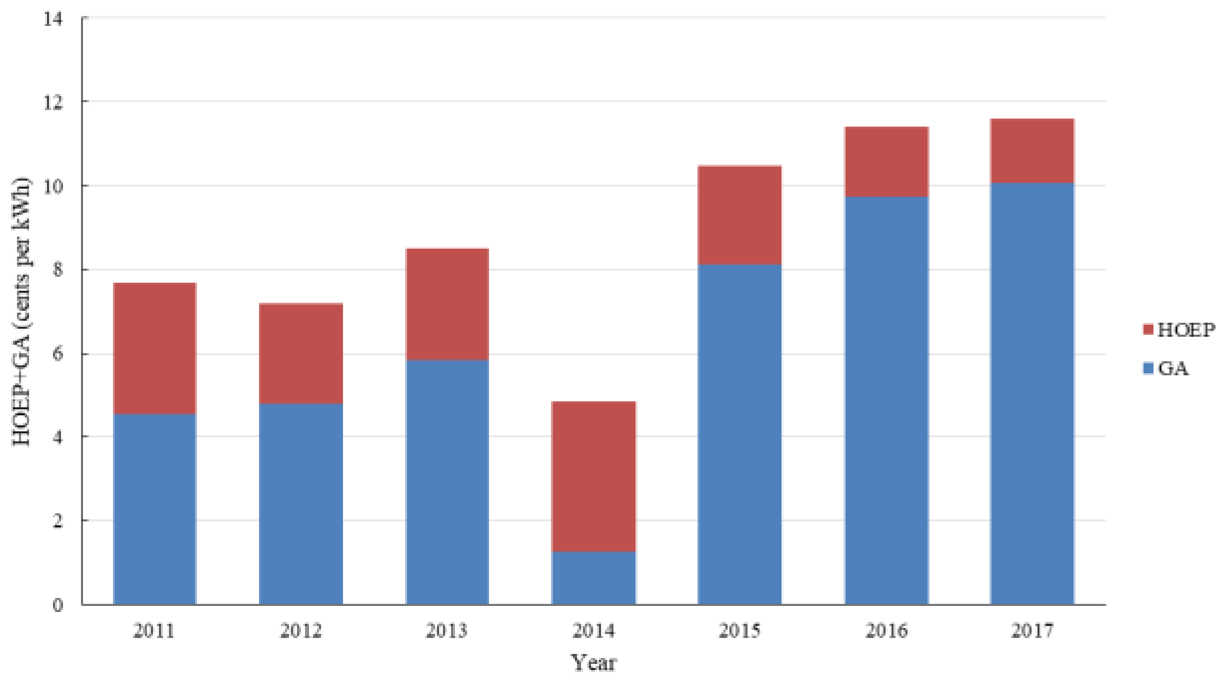


Figure 1-6. HOEP + GA from 2011 to 2017

A part of the rise in the GA in Ontario is because of the development of wind and solar power generation capacity via FIT programs. In her article, Stokes [1], cites the Auditor General of Ontario on stating that electricity bills increased 25% in the 2009-2014 period while the annual electricity cost in Ontario increased 2.5 billion dollars in the same period.

It is worth mentioning that a significant share of Ontario's generated electricity is not consumed by Ontario consumers while they still have to pay for the GA. The Office of Auditor General of Ontario's 2015 annual report states that Ontario curtailed and exported 11.9 million MWh and 95.1 million MWh of electricity between 2009 and 2014, respectively [9]. The same report also says that Ontario's revenue from power exports was CAD 3.1 billion less than the power generation cost between 2009 and 2014 [9]. In the same report, the Office of Auditor General of Ontario estimates 4.1 TWh of surplus power in Ontario in 2032 [9].

1.3 Heat decarbonization and its impact on electricity supply

A transition toward low-carbon and zero-carbon energy systems requires policy and technology transition in all the sectors of energy systems. The challenge in analyzing the decarbonization of energy sectors is the effect of changes in one sector on other energy sectors.

Decision-makers in one energy sector will seek their own advantage regardless of the overall operation of the system. This is a trend seen in modern energy systems with multiple stakeholders each seeking their own advantage. In conventional energy systems, a single decision-maker (the government) makes decisions on different aspects of the system trying to optimize the overall performance of the system.

The heat sector accounts for more than 50% of the energy consumption and 30% of carbon emissions in the UK [10]. As a result, any plan for the decarbonization of the heat sector in the UK will have a noticeable impact on the electricity supply and thus, has to be investigated. In a conventional energy system, the transition in the heat and electricity systems will be decided and implemented by a centralized decision-maker aiming at minimizing the overall cost of the system. However, a more realistic analysis will include independent decision-making in the heat and electricity supply systems.

1.4 Thesis layout

This thesis is focused on analyzing the interaction of different stakeholders in a carbon constrained system. Figure 1-7 shows how different stakeholders may interact with each other in a microgrid.

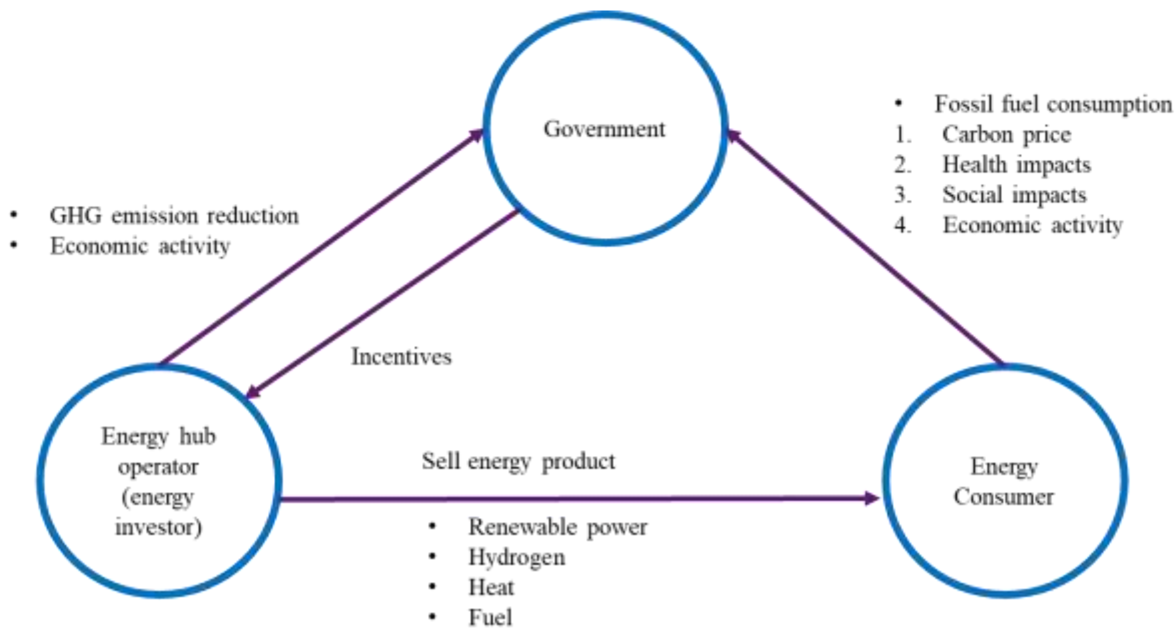


Figure 1-7. The interaction of stakeholders

The objective of this thesis is to develop models for analyzing the interaction of different stakeholders and energy sectors in energy systems. This objective has been pursued in two main areas:

1. Using game theory as a powerful concept in analyzing the interaction of various stakeholders in the presence of government incentives;
2. Investigating the cost-effectiveness of different renewable energy and energy storage technologies in reducing GHG emission in different energy sectors; and
3. Investigating the interaction of heat and electricity supply systems through multilevel modeling at a national level;

The contributions of this thesis to the energy system modeling and analysis literature are analyzing the objectives of different stakeholders interacting in a microgrid, analyzing the effect of government incentives on the development of renewable energy and storage technologies, analyzing the cost-effectiveness of government policies for the development of different energy conversion and storage technologies for GHG emission reduction, and investigating the interaction of the heat and electricity sectors at a national scale.

This thesis consists of eight chapters. The first chapter introduces the work via presenting the overview of the work, thesis objectives, and the thesis layout. Chapter two provides background information on Ontario's electricity system, the importance of energy storage systems, and the application of game theory in the modeling of energy systems.

Chapter three presents a deterministic model developed to simulate the operation of a wind farm and hydrogen generation and storage system in Ontario. The study presented in chapter three is by Haghi et al. [11], published in the Journal of Energy Policy. In chapter three, the objectives of different stakeholders in a microgrid are compared when different scenarios of renewable energy generation and hydrogen energy storage are considered. The stakeholders considered in this study are the government, the energy hub operator, and the energy consumer. The results of the study in chapter three show that the development of renewable energy generation technologies is in favor of the energy hub operator (energy investor) while the development of energy storage systems is in favor of the government as energy storage projects have the lowest GHG emission reduction cost.

In chapter four, multiple models are developed to simulate the operation of wind and solar power plants, Power-to-Gas systems, and battery-powered forklifts. The study presented in chapter four is by Haghi et al. [12], published in the International Journal of Hydrogen Energy. Different energy systems are compared by considering the capital costs and operation and maintenance cost of technologies, as well as health costs from GHG emission and taxed collected from the energy consumer and the energy hub operator. It is shown that wind and solar power generation are more cost-effective technologies for reducing GHG emissions when the electricity grid id highly dependent on fossil fuels. However, energy storage systems are a more cost-effective option for reducing GHG emission compared to wind and solar power generation considering Ontario's current electricity mix.

In chapter five, an optimization model is developed to assess the potential of battery-powered and fuel cell-powered forklifts in reducing GHG emission in Ontario. The study presented in chapter five is based on the work by Haghi, E., Shamsi, H., Dimitrov, S., Fowler, M., Raahemifar, K., accepted for publication in International Journal of Hydrogen Energy. In chapter five, a game theory model is developed to analyze the interaction of the government and the energy consumer, which is a commercial facility operating forklifts. The results of the study show that both battery and hydrogen technologies may be cost-effective for reducing GHG emissions. However, their cost-effectiveness depends on the social cost of carbon considered by the government.

In chapter six, an iterative approach is proposed to model the interaction of heat and electricity supply systems. The study presented in chapter six is based on the work by Haghi, E., Qadrdan, M., Wu, J., Jenkins, N., Fowler, M., Raahemifar, K., and is under review in the Energy journal. The model presented in chapter six is used to find the optimum selection of the heat and electricity supply technologies, while the effect of changes in one on the other is considered. Optimum selection of technologies was considered by solving two separate models iteratively until equilibrium is reached. The results of the iterative approach are compared with a centralized optimization model.

Chapter seven presents the summary and contributions of the studies and the recommendations for future research. Chapter eight presents the list of references cited in this thesis.

2 Background

2.1 Incentives for the development of renewable energy capacity

The growth in the level of CO_2 emissions has been a challenge worldwide. Conventional sources used for generating power and heat were responsible for more than 40% of the CO_2 emissions worldwide in 2009 [13]. To address these challenges, the development of renewable energy generation technologies has been pursued by governments all over the world.

One crucial obstacle in the development of renewable energy generation capacity is the need for investment capital. Investment in energy technology projects requires financial incentives in many cases since renewable projects have a higher capital cost compared to conventional energy technologies, are considered to be riskier due to technology and resource uncertainties, and could not benefit from economies of scale since they are of smaller scale compared to conventional technologies [14]. The same challenge exists for alternative heating and electricity supply technologies such as heat pumps and fuel cells. Carbon taxes, feed-in tariffs (FITs), feed-in premiums (FIPs), quota systems, cap and trade systems, and capital grants are incentive programs and policies designed by governments to overcome the problem of higher investment capital for distributed energy technologies. Each incentive program may benefit the development of a specific technology due to the unique efficiency, cost, capacity factor, and availability of different technologies.

The question is then how to define, combine, and use incentives in the most effective way to face the new challenges in the development of new energy technologies. While research focused on the development of distributed energy system and energy storage technologies is abundant in the literature, finding the most cost-effective policies and methods for increasing the penetration of these new technologies into national energy systems is an area that needs to be further investigated [15].

2.2 The role of energy storage in energy systems

Widespread deployment of renewable energy generation technologies causes technical challenges in electricity systems. Renewable energy generation technologies, such as wind and solar power are intermittent. The electricity generation profile of such technologies not only changes by weather conditions during a day, but also has a seasonal variation. Additionally, electricity generation by wind and solar technologies does not necessarily match the demand. While the output of technologies such as gas turbines can be adjusted based on the demand, wind and solar technologies do not have such capability.

Energy storage technologies are one of the solutions for controlling the variability of renewable energy generation technologies. Energy storage technologies enable the storage of energy when there is surplus generation for use when there is a demand for it. Combining energy storage and distributed energy technologies in microgrids with both electrical, industrial, and mobility energy demands is crucial for the efficient operation of the overall energy system. This is especially important for the province of Ontario with increasing penetration of intermittent wind and solar generation assets, while its nuclear electricity generation is both reliable and clean but provides inflexible baseload generation capacity.

2.2.1 Hydrogen energy storage

In this thesis, special attention is given to hydrogen due to its potential in reducing GHG emissions. Hydrogen as an energy vector can be used to store and transport energy. Hydrogen produced using electrolysis may be used to reduce GHG emissions in the industrial, residential, and transportation sectors. Additionally, hydrogen may be used for storing large amounts of power for long durations of time [16].

Hydrogen can be stored using the existing natural gas infrastructure by injecting hydrogen to the natural gas distribution systems. This concept for storing hydrogen is called "Power-to-Gas." In a Power-to-Gas systems, surplus electricity is converted to hydrogen which is then stored and directed to different applications in the industrial, transportation, and even residential sectors. It should be noted that in Ontario the power grid is dominated by baseload nuclear power, so the hydrogen energy storage is also useful for addressing large quantities of the excess off-peak baseload nuclear power, which is also a GHG-free source of power generation.

2.2.2 Battery energy storage

Batteries are the most widely used energy storage system [17]. Batteries are flexible in terms of installation locations which makes them suitable for many such applications [18]. For instance, batteries are recognized as suitable energy storage systems in hybrid wind and solar energy systems due to their high efficiency [19] . Additionally, batteries can be used in other applications such as grid reliability, residential systems, and electric vehicles. All these specifications have led us to investigate the effectiveness of battery energy storage in reducing GHG emission in Ontario in this thesis.

2.3 Game theory modeling of energy systems

Game theory is used in the modeling of energy systems to develop mathematical models which enable us analyze negotiation, conflict and cooperation between individuals, organizations and governments. Game theory is applied in energy systems studies to understand why an individual makes a particular decision and how the decisions made by one individual affect others. Organizational decisions and planning involve several levels of decision making with different priorities. Objectives at each level of the organizational hierarchy may be different and decision-makers within each level may be cooperative or non-cooperative [21]. In order to address compromises between the interactive decision-makers that exist in a hierarchical organization, multilevel decision-making techniques, motivated by Stackelberg game theory and presented by multilevel mathematical programming have been developed. In a multilevel decision-making process, decision-makers at the higher level are called the leaders and the decision-makers at the lower level are termed the followers. The decision-makers make their individual decisions in sequence with the aim of optimizing their respective objectives [22].

This decision-making process means that the leader has priority in making decisions and the follower reacts in full knowledge of the leader's decision; however, the leader's decision is implicitly affected by the follower's decision.

Most of these applications of game theory and multilevel programming have been focused on the planning of new technologies and their supply chain analysis. A summary of the reviewed literature focusing on the application of multilevel programming and game theory is presented in Table 2-1.

Table 2-1. Summary of reviewed literature on multilevel programming and game theory application

Number	Paper’s title	Application for game theory	Stakeholders
1	Security-constrained bi-level economic dispatch model for	Integrated natural gas and electricity systems	Two levels, economic dispatch for the electricity

	integrated natural gas and electricity systems considering wind power and power-to-gas process [22]		system and gas economic allocation
2	Game theory approach in decisional process of energy management for industrial sector [23]	Governing energy policy	Two levels, industry and environment
3	An interaction between government and manufacturer in implementation of cleaner production: a multi-stage game theoretical analysis [24]	Implementation of cleaner production	Two levels, government and manufacturer
4	A game theory analysis of market incentives for US switchgrass ethanol [25]	Biofuel incentives	Two levels, farmers and ethanol producers
5	An exploratory game-theoretic analysis of biomass electricity generation supply chain [26]	Power generation from biomass supply chain	Three levels, distributor, facility developer, and participating farmer
6	A Stackelberg game theoretic analysis of incentive effects under perceived risk for China's straw-based power plant supply chain [27]	Incentives for the biomass supply chain	Three levels, biomass power plants, middlemen, and farmers
7	Novel role of rural official organization in the biomass-based power supply chain in China: a combined game theory and agent-based simulation approach [28]	Biomass feedstock supply model for the biomass-based power	Three levels, farmer, broker and biomass plant

8	Palm biomass strategic resource management–a competitive game analysis [29]	Biomass industry	Two levels, industries at the same level
9	A game-theoretic analysis of implementation of cleaner production policies in the Chinese electroplating industry [30]	Implementation of cleaner production policy	Two levels, local government and a potentially polluting firm
10	Sustainable development by waste recycling under a three-echelon supply chain: A game-theoretic approach [31]	Waste recycling process supply chain	Three levels, collector, recycler, manufacturer
11	An evolutionary analysis of low-carbon strategies based on the government–enterprise game in the complex network context [32]	Adoption of a low-carbon strategy	Two levels, government and enterprises
12	For the sustainable performance of the carbon reduction labeling policies under an evolutionary game simulation [33]	Incentive policies related to the implementation of a carbon reduction labeling scheme	Two levels, any enterprise in the market
13	Selecting sustainable waste-to-energy technologies for municipal solid waste treatment: a game theory approach for group decision-making [34]	The municipal solid waste treatment options	Two levels, municipality and industry
14	Grid extension in German backyards: a game-theory rationale [35]	Grid extension	Multiple, communities paying for grid extension and use
15	Multi-objective game-theory models for conflict analysis in reservoir watershed management [36]	Economic and environmental concerns in reservoir watershed management	Two levels, environmental player and economic player

16	An adjustment in regulation policies and its effects on market supply: Game analysis for China's rare earths [37]	Government policy on rare earth extraction	Two firms acting on rare earth business
17	Consensual decision-making model based on game theory for LNG processes [38]	Liquefied Natural Gas (LNG) processes	Three levels, one leader (liquefaction process) and two followers (the compressor and the main heat exchanger)
18	A software based simulation for cleaner production: A game between manufacturers and government [39]	Cleaner production policy	Two levels, government and manufacturers
19	Game modeling and policy research on the system dynamics-based tripartite evolution for government environmental regulation [40]	Government environmental regulation	Three levels, government, polluting enterprises, and society
20	Game model to optimally combine electric vehicles with green and non-green sources into an end-to-end smart grid architecture [41]	Combine electric vehicles into a smart grid	Two levels, smart grid and electric vehicle
21	An inexact bilevel simulation–optimization model for conjunctive regional renewable energy planning and air pollution control for electric power generation systems [42]	Renewable energy planning and air pollution control	Two levels, environmental sector and energy sector
22	Determining tax credits for converting non-food crops to biofuels: an application of bilevel programming [43]	Design of tax credits for the production of biofuels	Two levels, government and petrochemical industry

As can be seen in Table 2-1, game theory is a useful concept to address emerging energy and environment issues when multiple stakeholders are engaged. The most important problem in the design of renewable energy incentives is the willingness of governments for implementing new and clean technologies and the resistance of investors and customers in using them because of the high cost and uncertainty in the profitability. This is the context of our work, and as a result, we have aimed at addressing such challenges using the game theory concept and multilevel optimization.

Similarly, we have used a bilevel model for analyzing the interaction of the heat and electricity sectors.

The reason for using a multilevel programming approach rather than a single level approach is the existence of different stakeholders in the system which may have conflicting objects. Conflicting objects means that an increase in the benefit of one stakeholder leads to a decrease in the benefit of others. Hence, it is more reasonable to model the stakeholders at different levels. Additionally, literature review shows that bilevel programming approaches lead to results with more realistic patterns in comparison to single-level models since in bilevel programming approaches all objectives are taken into account.

Table 2-1 and the literature review in the previous section also show that most of the game theory applications have been formulated with a bilevel optimization problem. The complexity of solving problems with more than two players (stakeholders) have made the researchers limit their problems to two stakeholders where different solving methods have been suggested. However, a few papers have expanded their work to systems with more than two stakeholders and have molded systems with three stakeholders.

2.4 Conclusion

Reviewing the literature focused on the incentives for the development of renewable energy capacity shows that different government incentives will lead to different results both in energy capacity development and objectives of different stakeholders. As a result, analyzing the interaction of different stakeholders in a microgrid is of importance when government incentives are to be designed. Additionally, it was found out that energy storage technologies are effective options for reducing GHG emissions, especially when surplus clean electricity is available.

Finally, game theory was recognized as a powerful concept for modeling the interaction of different stakeholders. Game theory has been used in many areas where independent decision making of stakeholders needs to be analyzed.

3 Investigating the effect of renewable energy incentives and hydrogen storage on advantages of stakeholders in a microgrid

The following section is based on work by Haghi et.al [11], published in the Energy Policy journal. Contribution of authors is detailed in the Statement of Contributions section.

3.1 Introduction

The growth in the level of CO_2 emissions has been a challenge worldwide. CO_2 emissions from energy consumption accounted for 60% of global GHG emissions in 2010. [44]. World's energy consumption and CO_2 emissions are expected to increase by 56% and 46% between 2010 and 2040, respectively [45]. Despite the importance of renewable energy technologies in overcoming this challenge, successful integration of such technologies can only be achieved after overcoming varied obstacles. One important obstacle is the need for investment capital. Investment in renewable energy projects requires financial incentives as such projects typically have higher capital costs than the conventional energy generation systems and are in some cases considered to be riskier due to technology and resource uncertainties. Renewable energy projects are generally of a smaller scale in comparison with the conventional energy production projects and consequently could not benefit from economies of scale [14].

The objective of this research is to determine how different incentives contribute to the perceived viability of a microgrid project from the perspective of different stakeholders, i.e., the government, the energy hub operator and the energy consumer and also to examine the potential for hydrogen energy storage within a microgrid. Previous studies have examined the implementation of new distributed energy technologies confounding the objectives of all stakeholders. However, in an energy system the entity that will invest in and implement a new distributed energy generation and transformation technology is a commercial firm with their own motivations independent of other stakeholders. Unique to this work, is the analysis of motivations of each stakeholder independently, which will allow for better policy development and increased implementation of distributed energy technologies.

To overcome the problem of higher investment capital for renewable energy projects, many countries have started incentive programs and policies. Some of the common policies which aim to expand renewable energy infrastructure include carbon taxes, feed-in tariffs (FITs), premium payments, quota systems, cap and trade systems, and capital grants. Different policies have contributed to reducing Greenhouse Gas (GHG) emissions through incentives provided to renewable energies; however, the remaining question is how to define, combine and use incentives in the most profitable manner to face the new challenges in the development of renewable energy technologies. The importance of this question emerges from the fact that there are several renewable energy technologies developed with different characteristics such as efficiency, cost, capacity factor, and availability. At the same time, there are several programs to incentivize renewable energy technologies and each of these incentives may benefit certain technologies or stakeholders in an energy system. Although some research has been dedicated to development of renewable energy technologies, finding the most efficient policies and methods for increasing the penetration of renewable energies into national energy systems considering the objectives of all stakeholders has attracted less attention and has yet to be further investigated [15].

This research aims to develop a simulation model of a microgrid in which hydrogen and wind power are produced in different operational scenarios. This simulation model is used to investigate the cost-efficiency and effect of renewable energy incentive schemes on the advantages of different stakeholders interacting in the microgrid. The analysis is done in the context of distributed generation. Such context was chosen for the analysis because of an increase in the penetration of distributed generation in developed countries and the significant role distributed generation is expected to play in future electricity supply. Distributed generation can substantially reduce carbon emissions, thereby contributing to the commitments of most developed countries to meet their GHG emission reduction targets. Most of the targets are typically set based on the Paris Climate Accord within the United Nations Framework Convention on Climate Change (UNFCCC). Also, the presence of energy generation and storage close to the energy demand may increase the power quality and the reliability of electricity delivered to sensitive end users. An important factor in increasing the penetration of distributed generation has been the restructuring of power markets [46].

While the application of distributed generation can potentially reduce the need for traditional electrical transmission system expansion, managing a potentially huge number of distributed generation facilities creates a new challenge for operating and controlling the network safely and efficiently. Note that offsetting transmission system expansion benefits the government, but does not specifically benefit the end user. This challenge can be partially addressed by microgrids [47]. Microgrids are low voltage distribution networks comprising various distributed generators, storage devices and controllable loads that can operate interconnected or isolated from the main distribution grid, as a controlled entity [46]. Microgrids coordinate distributed generation facilities in a consistently more decentralized way, thereby reducing the control burden on the grid and allowing them to provide their full benefits [47].

In the microgrid proposed in this study, hydrogen is produced via electrolysis using grid electricity and/or wind power. Wind power has been considered a promising substitute for conventional sources of electricity because of its abundance, adaptability to the existing land use, nonpolluting character, and increasing cost-effectiveness [48]. Additionally, among all hydrogen production pathways, electrolytic hydrogen production via wind power is considered to have the lowest GHG emissions. Moreover, wind energy has the lowest levelized cost of electricity among renewable energy sources after hydropower [49]. As a result, production of electrolytic hydrogen via wind power seems to be of noticeable potential.

Using hydrogen energy for storing and transporting energy has attracted great attention in recent years. For instance, the European Union launched a joint technology initiative to spend almost one billion Euros over six years for hydrogen and fuel cell technologies [50], [51]. Electrolytic hydrogen not only can replace fossil fuels in both industrial and mobility demands but also can be used as a practical option for storing large amounts of power for long durations of time [16]. The use of electrolytic hydrogen production as energy storage that uses the existing natural gas distribution system is defined in the concept of ‘Power-to-Gas. The Power-to-Gas concept proposes to convert the surplus electrical energy to chemical energy by producing hydrogen which can then be directed in multiple application pathways [52]. The block diagram of the Power-to-Gas concept is shown in Figure 3-1.

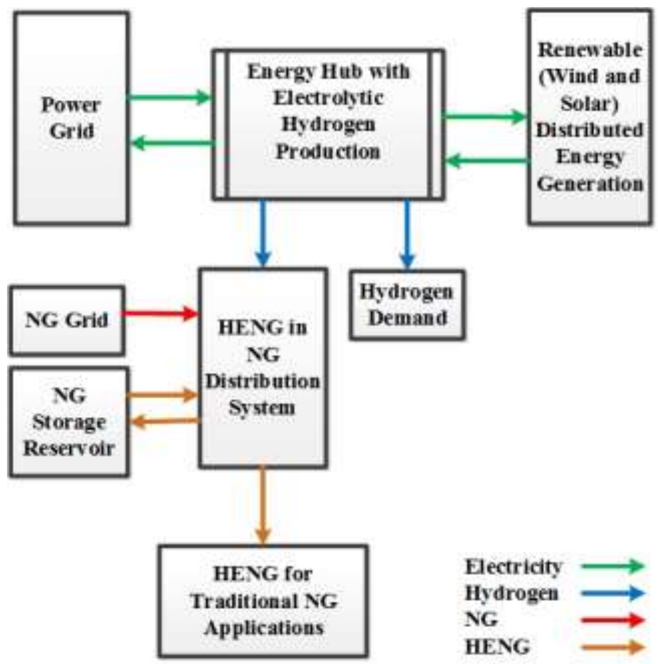


Figure 3-1. Power-to-Gas concept block diagram

Figure 3-2 shows the Ontario's electricity supply mix for 2015. As can be seen, about 90% of Ontario's electricity supply is generated from fossil-free resources. Hydrogen generation provides energy storage benefits to make maximum use of the clean energy in the electrical grid.

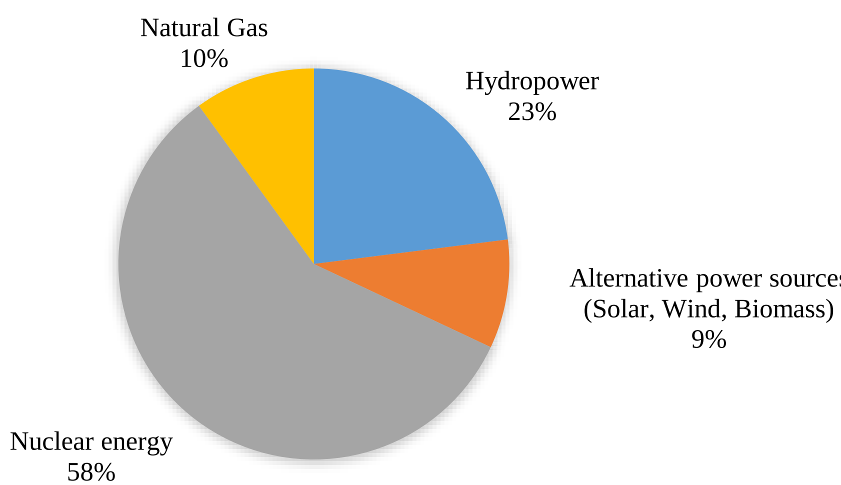


Figure 3-2. Ontario's electricity supply for total delivered energy 2015 [53]

The research focused on analyzing the cost-effectiveness of different renewable energy policies is abundant in the literature. de Arce et al. [54] for instance, compared different incentive policies (carbon tax, FIT, premium payment and quota system) for the development of renewable energy in a modeled simplified radial power network, using price-responsive demand. The incentive schemes were compared at different congestion levels in terms of energy prices, renewable energy generation, CO_2 emissions, and social welfare. The authors in [54], found that subsidy policies (FIT and premium payments) are more cost-effective in reducing CO_2 emissions compared to policies that apply penalties or taxes when assuming oligopoly competition and policies in which customers do not directly pay back for the subsidies. Kitzing [55], used variance portfolio analysis to identify the risk implications of FITs and feed-in premiums (FIPs). Using cash flow analysis, Monte Carlo simulations and mean–variance, Kitzing [55] analyzed the inherent relationship of risk and return for renewable energy under different incentive policies. An offshore wind project was used to show the impact of policies on both the private investor, defined as the attractiveness of investment, and society, defined as required support to be paid. The results showed that while FITs provide the same attractiveness for investment, they systematically require lower levels of direct support than FIPs since they expose investors to less market risk.

Among all methods for investigating the profitability of renewable incentive schemes, calculating the net present value (NPV), internal rate of return (IRR) and payback period (PBP) of renewable energy projects has been the most prevalent method. This method has been used for different incentive schemes as well as different renewable energy technologies. Falconett et al. [56], for instance, evaluated the NPV of renewable energy projects under different support mechanisms and calculated how much the different policies increased the NPV of the project. The authors in [56], investigated the effect of FITs, net metering (NM), renewable energy certificates (RECs) and governmental grants as well as the economic effect of carbon credits on small-scale hydroelectric, wind energy and solar PV technologies. They concluded that FITs are the best mechanisms for increasing the profitability of solar PV systems and wind energy projects. In addition, they also showed that the government grants and carbon credits are secondary support mechanisms compared to FIT and RECs. Campoccia et al. [57], analyzed FIT support mechanisms for promoting PV systems using profitability measures of discounted cash flows (DCF), PBP, NPV, and IRR, for different sizes of PV systems. The result of their study showed that a specific FIT can sometimes be inconvenient for the producer and that different ways of implementing FIT support policies in various countries can lead to significantly different results.

de Arce et al. [58], evaluated the effect of UK FIT on decentralized small wind-energy installations at the household and building level in urban areas using NPV criteria for assessing commercial purchases of small wind systems by building owners. The authors concluded that the proposed tariff amount in the UK will not significantly boost the economic attractiveness of investigated sites. Coffman et al. [59], assessed the impact of Hawaii's solar PV tax credit policy for the development of household PV systems with different levels of generated electricity fed to the grid. The authors in [59], estimated the effect of tax credit incentive for households to install PV by calculating PBP and IRR for PV installation. The results showed that IRR for a typical Hawaii household is 25% and 16% with and without the state tax credit, respectively. It was also estimated that the PBP for investing in PV with and without the state tax credit was 3.3 and 6 years (statewide average), respectively. Zhao et al. [60], calculated appropriate FIT values on the basis of different financing scenarios of a solar–coal hybrid power plant. The FIT was calculated so that the investment could earn a rate of return to offset the inflation of approximately 8% for the investors to allow profitability. Ramírez et al. [61], analyzed the cost-efficiency of using FIT and net metering schemes on the profitability of PV projects. The analysis was done to show the minimum levels of tariff values and the specific combination of support schemes that should be promoted. Results showed that in most cases, PV systems are not profitable without the support of an electricity compensation scheme. However, it was concluded that a combination of FITs and net metering schemes is a viable option for PV development in most of the countries considered (European countries) using the PV systems studied and adopting suitable levels of tariff prices. Mir-Artigues et al. [62], developed a financial model to investigate combining FITs with investment subsidies and soft loans. The results showed that the policy costs of combinations were the same as for the FITs-only option. Therefore, combining deployment instruments is not a cost-containment strategy. However, combinations may lead to different inter-temporal distributions of the same amount of policy costs, and thus, affect the social acceptability and political feasibility of renewable energy support differently.

From the literature review the following points can be concluded:

1. FIT is thought to be an effective incentive scheme for promoting investment in renewable energy;

2. Investigating the efficiency and cost-effectiveness of the capital grant scheme has been the focus of much less attention than other renewable energy incentive schemes, especially FITs;

3. Efficiency and cost-effectiveness of a combination of schemes due to its potential and the effect of different schemes which are implemented at the same time are important topics to consider;

4. Most of the research in the efficiency of renewable energy schemes has been dedicated to the effect of the scheme on promoting investment in renewable energy. Most studies have used NPV criteria for analyzing the efficiency of a certain scheme or to find the value of an incentive scheme. However, this is only in favor of one of the stakeholders in an energy system (the investors in renewable energy technologies); and

5. Renewable energy technologies on which the effect of incentive schemes have been investigated the most extensively are firstly solar systems like the ones used by Dusonchet and Telaretti [63], to compare NPV and IRR for different sized PV systems, and in Dusonchet and Telaretti [64], to perform a comparative economic analysis among FITs and tradable green certificates (TGC) implemented in western European countries. The reason for the attention toward solar systems is the possibility of using solar systems at rooftops which facilitates their use in residential buildings. However, the technology application and financial incentives have not been well considered from the perspective of different stakeholders and energy storage technologies, and thus there are still challenges for commercialization of technologies such as of Power-to-Gas.

3.2 Methodology

In this study, three stakeholders in the microgrid, each seeking their own objectives will be considered. These three stakeholders are the government, the energy hub investor (the energy hub operator), and the energy consumer. Traditionally, the consumer would purchase energy (i.e., electricity, natural gas, or transportation fuel) from a large, and often regulated energy hub operator. Previous studies have examined the implementation of new distributed energy technologies confounding the objectives of all the stakeholders. Unique to this work, is the analysis of the motivations of each stakeholder independently, which will allow for better policy development and increased implementation of distributed energy technologies. Considering the modeled microgrid, the advantage of each stakeholder is defined as follows:

Energy consumer: The energy consumer seeks the objective of minimizing the cost. In this study, the cost for the energy consumer is defined as the sum of the energy consumer's payment to the energy hub operator and the government. The energy consumer in this microgrid has two options: buying the relatively less expensive natural gas fuel and paying more emission cost, or buying the relatively more expensive hydrogen fuel and paying less emission cost. The energy consumer pays the emission cost to the government and the price of hydrogen to the energy hub operator.

Energy hub operator: The energy hub operator seeks the objective of maximizing the net present value (NPV) from investment in renewable energy and energy storage technologies. The energy hub operator gains revenue from selling hydrogen to the energy consumers, and/or selling renewable power (wind, in this case) to the grid. However, in the transition toward a cleaner economy an energy hub operator also benefits from incentives paid by the government to promote clean energy infrastructure. In a more complicated simulation, the energy hub operator may also be able to sell natural gas and electricity to the consumer. However, this case is not considered in this study.

Government: The government seeks to spend the minimum amount of money in incentives contributed, or minimize the net amount of money required to decrease one kg of CO_2 emission. The government seeks to reduce GHG emissions and urban air pollution emissions in two ways: by incentivizing the generation of renewable energy, and by taxing CO_2 emission via carbon price. As a result, the government interacts with the energy hub operator via paying incentives (this incentive may be paid through different programs as explained later on) and interacts with the energy consumer via taxing its CO_2 emission with carbon price.

Wind power is an energy source while hydrogen is an energy vector (i.e., a medium to store and transport energy), therefore, they can't be compared via direct metrics. However, investing in wind power for reducing CO_2 emissions and investing in hydrogen infrastructure for energy storage achieve the same outcome of reducing GHG emissions, and thus can be considered as alternative policies in competition for government funding and investor support, all while requiring consumer acceptability. Figure 3-3 provides a schematic representation of interactions among stakeholders.

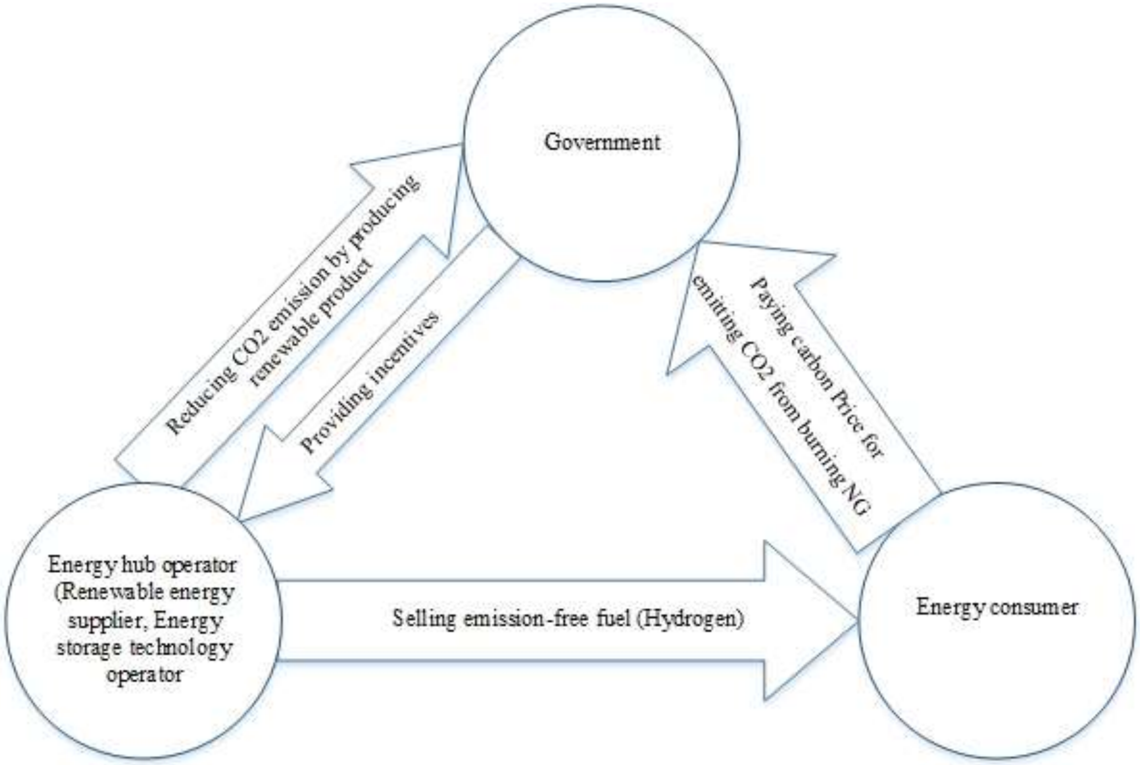


Figure 3-3. Stakeholders' interaction

For each scenario, different incentive programs are investigated and compared with each other using the following criteria:

Annual payment by the government (CAD per year): The total amount of money in 2015 Canadian Dollars (CAD) paid by the government to the energy hub operator through a FIT program to incentivize renewable energy generation. 2015 was selected for two reasons: 1. A full year hourly electricity price is available for 2015, and 2. In 2015 Ontario grid did not have any coal energy production.

Capital grant paid by the government (CAD): The amount of money paid by the government to the energy hub operator in form of a capital grant in the first year of the project to offset part of the capital investment cost.

Government's revenue per kg of CO_2 (CAD per kg): As outlined earlier, the government seeks to increase the penetration of renewable energy in the system in two ways:

1. Taxing CO_2 emitted from conventional fuel using a carbon price. The government makes money from this channel.
2. Incentivizing the generation of renewable energy. Here, the government pays money.

Note that consumer acceptability is not specifically considered in this study beyond carbon pricing; however, it will be the subject of future studies. Consumer acceptability metrics are confounded with government objectives but will primarily be net energy cost (i.e., cost of electricity, natural gas, and hydrogen, as well as carbon pricing, to meet all their energy requirements). Other consumer acceptability metrics include issues such as safety, reliability, technology readiness, reduction in local air pollution, and local job creation.

The government's revenue per kg of CO_2 emission equals the amount of money the government awards minus the amount of money it collects from carbon tax per kg of CO_2 emission reduction. If this number is positive, it means the government is spending money to reduce each kg of CO_2 emission. If the government's revenue is negative, it means the government has a net positive revenue generation for each kg of CO_2 emission reduction. The lifetime of the incentive program, as well as the project lifetime, is assumed to be 20 years. The amount of annual incentives awarded by the government and the carbon tax received from the energy consumer in 20 years is brought back to the first year value and is added to the capital grant awarded by the government to find the sum of the money the government pays in 20 years. This amount is divided by the carbon emission reduction in 20 years to find the value of government's net investment.

Government's expenditure per kg of CO_2 (CAD per kg): The government's expenditure per kg of CO_2 is the amount of money the government pays to reduce one kg CO_2 emission by awarding incentives. This number has always a positive value. The annual amount of money spent by the government in 20 years is brought back to the first year value and is added to the capital grant paid by the government to find the sum of the money the government spent over 20 years. This amount is divided by the carbon emission reduction in 20 years to find the value of the government's expenditure.

The government's revenue calculation is used to compare incentive programs in a scenario. The government's expenditure criteria, however, is used to compare programs in different scenarios. The reason for the distinction is that the amount of CO_2 emission reduction varies in different scenarios. As a result, the denominator for calculating government's revenue will not be the same in different scenarios and this leads to misconception when the revenue is a negative number if government's profit is used for comparing scenarios.

NPV of the energy hub operator (CAD): Net present value (NPV) of the energy hub operator is the net present value of the investment of the energy hub operator in an energy project considering the revenue gained from selling renewable products accompanied with incentives. The criteria for evaluating the efficiency of an incentive scheme for promoting a certain renewable infrastructure will be the NPV of the energy hub operator.

Additional cost of the consumer (CAD): Based on different carbon prices, energy consumer should either pay carbon price imposed on emission from conventional fuel consumption or buy emission-free hydrogen to replace fossil fuel consumption. The consumer has to pay this amount as long as there is a carbon price in place and is the additional cost of the consumer compared to the case where there is no carbon price.

Amount of CO_2 prevented to be emitted annually (kg CO_2 per year): Government policies in incentivizing renewable energy and imposing carbon prices prevent the emission of a certain amount of CO_2 annually.

3.2.1 Microgrid description

The microgrid simulated in this study includes three levels of supply, conversion and storage, and primary end user. In the supply level, water, electricity from the grid, electricity from the wind farm and natural gas from natural gas pipeline enter the microgrid. The generated wind power can also be sold to the grid. In the conversion and storage level, hydrogen is produced via the water electrolysis process with an alkaline electrolyzer using the electricity from the grid and/or the wind farm. The produced hydrogen may be directed in two ways: hydrogen may be blended with natural gas and the mixture is used as Hydrogen-Enriched Natural Gas (HENG) in two generator sets internal combustion engines (ICEs) and a drying furnace in primary end user, or it may be stored (aboveground or underground) for later use. Figure 3-4 shows an overview of the microgrid considered in this study.

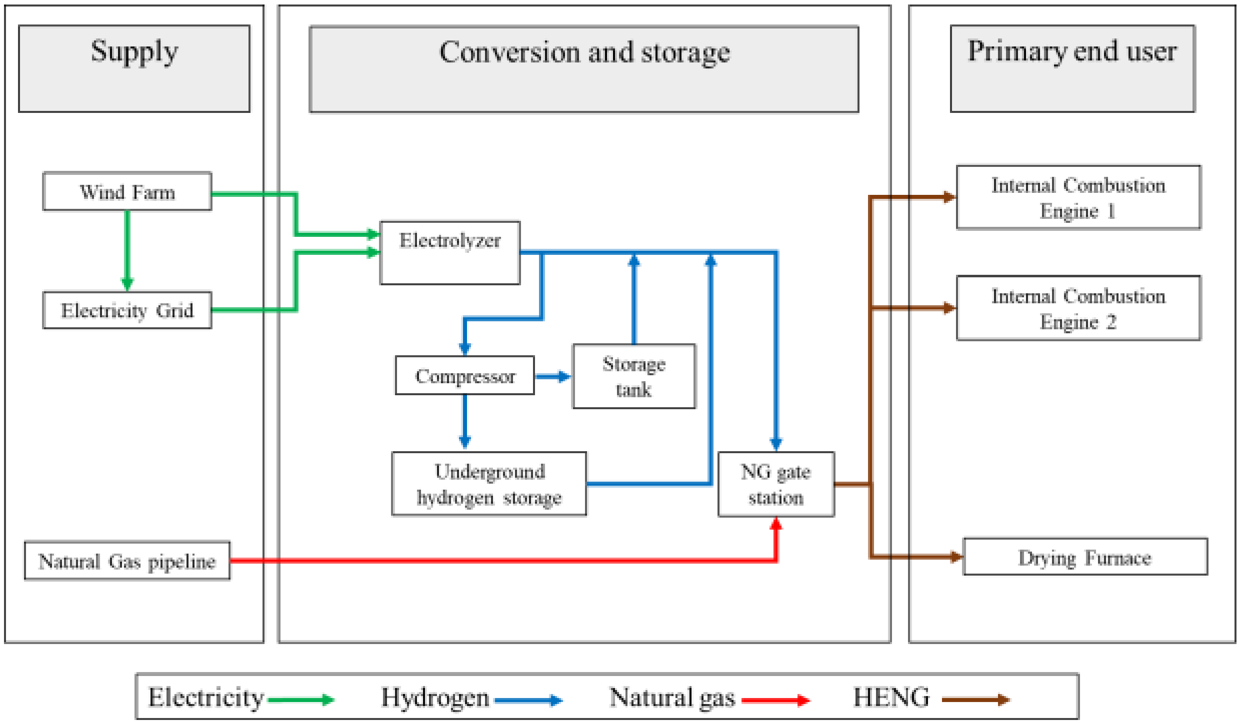


Figure 3-4. Overview of the microgrid considered in this study

The electrolyzer used in the microgrid is an alkaline electrolyzer with maximum and minimum hydrogen production rate of 150 m^3 per hr and 25 m^3 per hr, respectively. It is assumed that 5.9 kWh of electricity is used to produce each m^3 of hydrogen and the hydrogen leaves the electrolyzer at a pressure of 30 bars.

Hydrogen in gaseous form is generally stored in two ways: aboveground storage (as a compressed gas in a tank) and underground storage. For aboveground storage, hydrogen is stored in a tank and is used for both pressure regulation and short term buffer or staging storage of hydrogen. Underground storage is used for bulk hydrogen storage. Underground storage is less expensive than the aboveground storage on a per kWh basis; however, it is only reasonable to develop underground storage for large scale hydrogen storage [65]. Four types of geological storage options have been examined for hydrogen storage in the literature. These four types include salt caverns, depleted oil & gas reservoirs, aquifers, and hard rock caverns [66]. In the proposed microgrid, hydrogen is stored underground in a fully depleted natural gas production reservoir which acts as a seasonal storage. For model simplicity, hydrogen is only added to the underground storage reservoir in the first 6 months of the year (from January to June) and is only extracted from the underground storage reservoir in the last 6 months of the year (from July to December) to meet the demand. In reality, the interaction with the reservoir can be much more dynamic. 1.25 kWh of electricity is needed to compress hydrogen to 170 bars (aboveground storage tank pressure) and 0.78 kWh of electricity is needed to compress hydrogen to 138 bars (underground storage operation pressure). It is assumed that hydrogen needs no compression if it is going to be delivered to the consumer without any storage.

An 18 MW wind farm will constitute the baseline of this study. The turbines used in the model are V90 1.8 MW Vestas wind turbines. Knowing the hourly wind speed for the region, we investigated the capacity factor of different wind turbines and "Vestas V90 1.8 MW" had the highest capacity factor among all models/brands investigated. As a result, this wind turbine model was used in our modeling. The wind turbine characteristic curve is from the manufacturer catalog and shown in Table 3-1.

Table 3-1.Assumed wind turbine characteristics (data from [67])

Wind turbine characteristic	**Quantity**
Cut-in wind speed	4 meters per second
Rated wind speed	12 meters per second
Cut-out wind speed	25 meters per second
Hub height	80 meters

The hourly wind speed for the region of Sarnia, where the microgrid is considered to be, is known for a typical year. The original measurements were conducted at 10 m above the ground level. The measured values were adjusted to match the height of the nacelle at 80 m above the ground level using a Hellman exponent of 0.14 for the region.

The energy consumer is assumed to be a factory using two internal combustion engines and an agricultural product drying furnace. Fuel input for gas spark ignition engine CHP from the Catalog of CHP Technologies [68] (typical performance parameters) and the natural gas consumption for the furnace is assumed to be 150 m^3 per hr. Table 3-2 shows the natural gas demand.

Table 3-2. Assumed natural gas demand

Device	Fuel input (MMBtu per hr), HHV	Natural Gas input (m^3 per hr)
ICE 1 (System 5 engine in the catalog)	76.66	1638
ICE 2 (System 4 engine in the catalog)	28.12	600
Drying Furnace	NA	150
Total	NA	2388

Considering the technical and operational constraints and knowing natural gas consumption, a hydrogen consumption of 8.22 kg per hr is calculated for replacing 4% of fuel consumption by volume. The assumption in the microgrid is that the energy hub operator signs a contract that guarantees to supply the required amount of hydrogen to the consumer in each hour of the year at a certain price.

The consumer price for hydrogen is assumed to be the price for hydrogen that makes it 'break even' for the natural gas consumer to replace the natural gas consumption with hydrogen considering the natural gas price and the carbon tax imposed on the consumer while accounting for the energy content of the two fuels in the blend. As a result, the sum of fuel cost (FC) and carbon cost (CC) in both cases should be equal as shown in Equation 3-1.

$$FC_1 + CC_1 = FC_2 + CC_2 \qquad 3\text{-}1$$

In which

$$FC = Hc \times Hp + NGc \times NGp \qquad 3\text{-}2$$

In Equation 3-2, Hc is hydrogen consumption in kg per hr, NGc is natural gas consumption in MMBtu per hour, Hp is hydrogen price in CAD per kg and NGp is natural gas price calculated based on 2015 average Henry Hub natural gas spot price. The prices consumer willing to pay for hydrogen at different carbon prices are shown in Table 3-3.

Table 3-3. Hydrogen consumer price

Carbon price (CAD per tonne)	Hydrogen price (CAD per kg)
0	0.49
30	0.74
50	0.91

The reasons for the relatively low consumer hydrogen price are 1. Low price of natural gas and 2. Low carbon emission price. In other words, as both the price for primary fuel (natural gas) and emission tax imposed on it are low, the energy consumer is willing to pay a low price for hydrogen energy. This issue shows the importance of implementing policies toward the support of hydrogen infrastructure either in increasing the price of hydrogen energy competitor (natural gas) or bolding advantage of hydrogen (lower emission) by increasing carbon price.

The consumer price for wind power is assumed to be equal to Hourly Ontario Electricity Price (HOEP) at the hour the power is sold to the grid. The energy hub operator's profit, however, doesn't come from the consumer payment only; energy hub operator also receives incentives from the government. It is also assumed that the energy hub operator can sell wind power to the grid at any time; however, the selling price differs considering different policies.

The characteristics of components of the microgrid used in the economic analysis are shown in Table 3-4. All values are in 2015 CAD. The values from different references were adjusted to 2015 values using the "chemical engineering plant cost index" and the exchange rate of one US dollar equal to 1.31 CAD. The values for electrolyzer stack replacement are from consulting with industrial partners.

Table 3-4. Assumed economic characteristics of microgrid components

Component	**Capital cost**	**Annual operation and maintenance cost**	**Lifetime (years)**
Wind turbine [69]	CAD 2165 per kW	3% of capital cost [69]	20
Electrolyser [70]	CAD 1050 per kW	4% of capital cost	20
Electrolyser stack replacement	30% of electrolyzer capital cost	Already included in electrolyzer operation and maintenance cost	10
Compressor [71]	CAD 5300*(storage size(kW))+ 24,000	4% of capital cost	20
Storage tank [71]	CAD 1410 per kg of hydrogen storage capacity	0.5% of capital cost	20

CO_2 emission from the grid is calculated based on the share of each source in the grid mix with specific emission factors presented in Table 3-5.

Table 3-5. Assumed electricity source emission factors [72]

Electricity source	Emission factor (kg of CO_2 per MWh)
Nuclear	17
Gas	622
Hydro	18
Wind	14
Solar	39
Biofuel	177

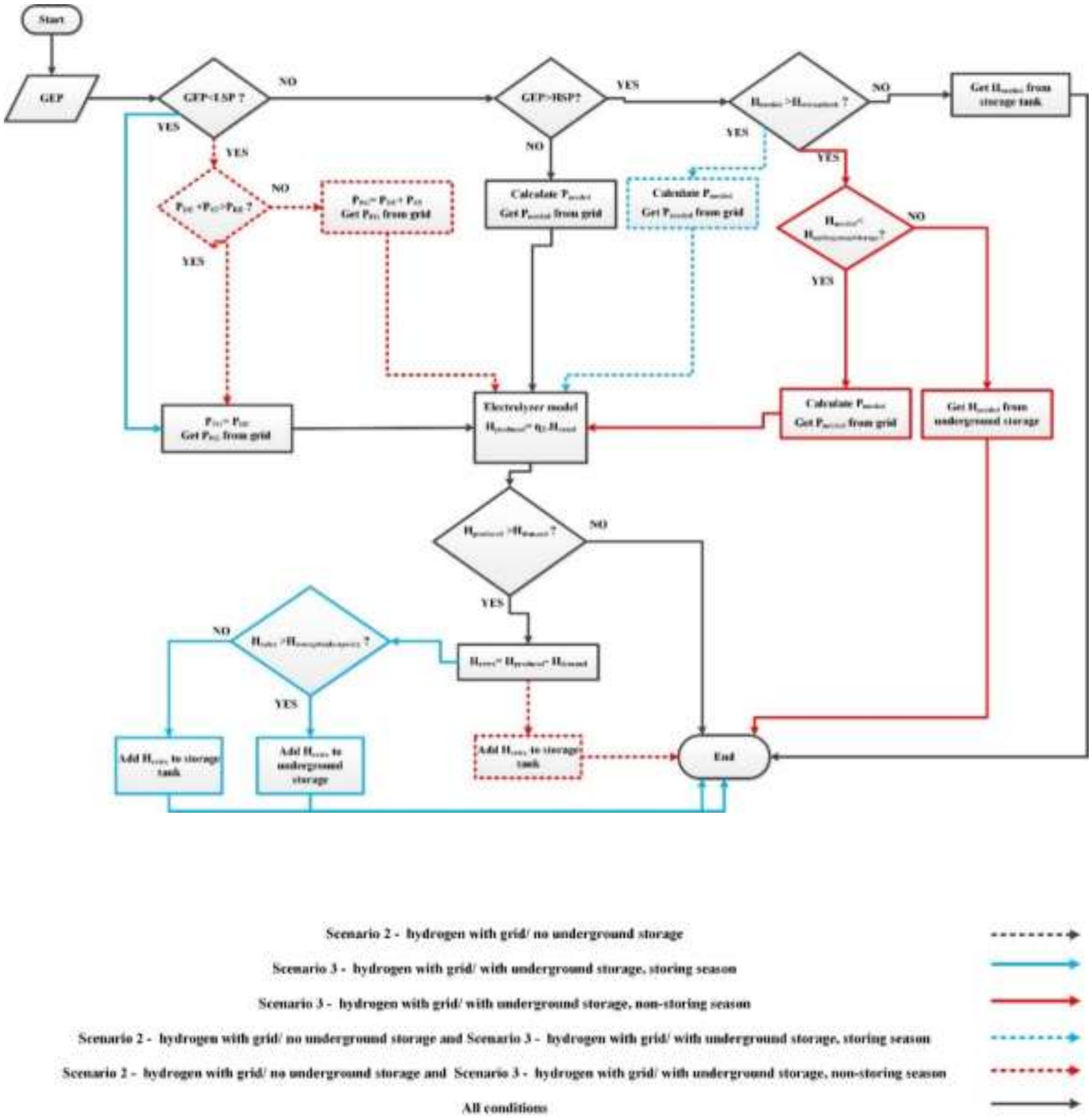
All scenarios are modeled hourly using MATLAB/SIMULINK. The modeling period is one year (8760 hours).

3.2.2 Scenarios

The following six scenarios for energy hub operation are investigated in this study.

Scenario 1: The energy hub operator is a renewable energy hub operator that generates only wind power and is able to sell the generated power to the grid at any time. The price for selling wind power is determined via a FIT program (Wind generation only).

Scenario 2: Hydrogen is produced using grid electricity only. Electricity is bought from the grid at the HOEP to fill the aboveground storage tank when the price of electricity is lower than a certain low set price (LSP) limit which is assumed to be 23 CAD per MWh. When the price of grid electricity is higher than a certain high set price (HSP) limit which is assumed to be 30 CAD per MWh, the electrolyzer is shut down and the hydrogen stored in the storage tank is used to meet the hydrogen demand. When the price of grid electricity is between LSP and HSP, the electrolyzer is used to produce hydrogen to meet the immediate demand (no adding to or extracting from storage in this case). If there is no stored hydrogen in the tank, electricity is bought from the grid at any price to produce hydrogen in order to meet the immediate demand. The storage tank considered in this scenario is small (capacity of storing 50 kg of hydrogen) and as a result, the system is buying electricity from the grid at almost every hour of the year. The flowchart for this scenario is shown in Figure 3-5 (Hydrogen with grid/ no underground storage).



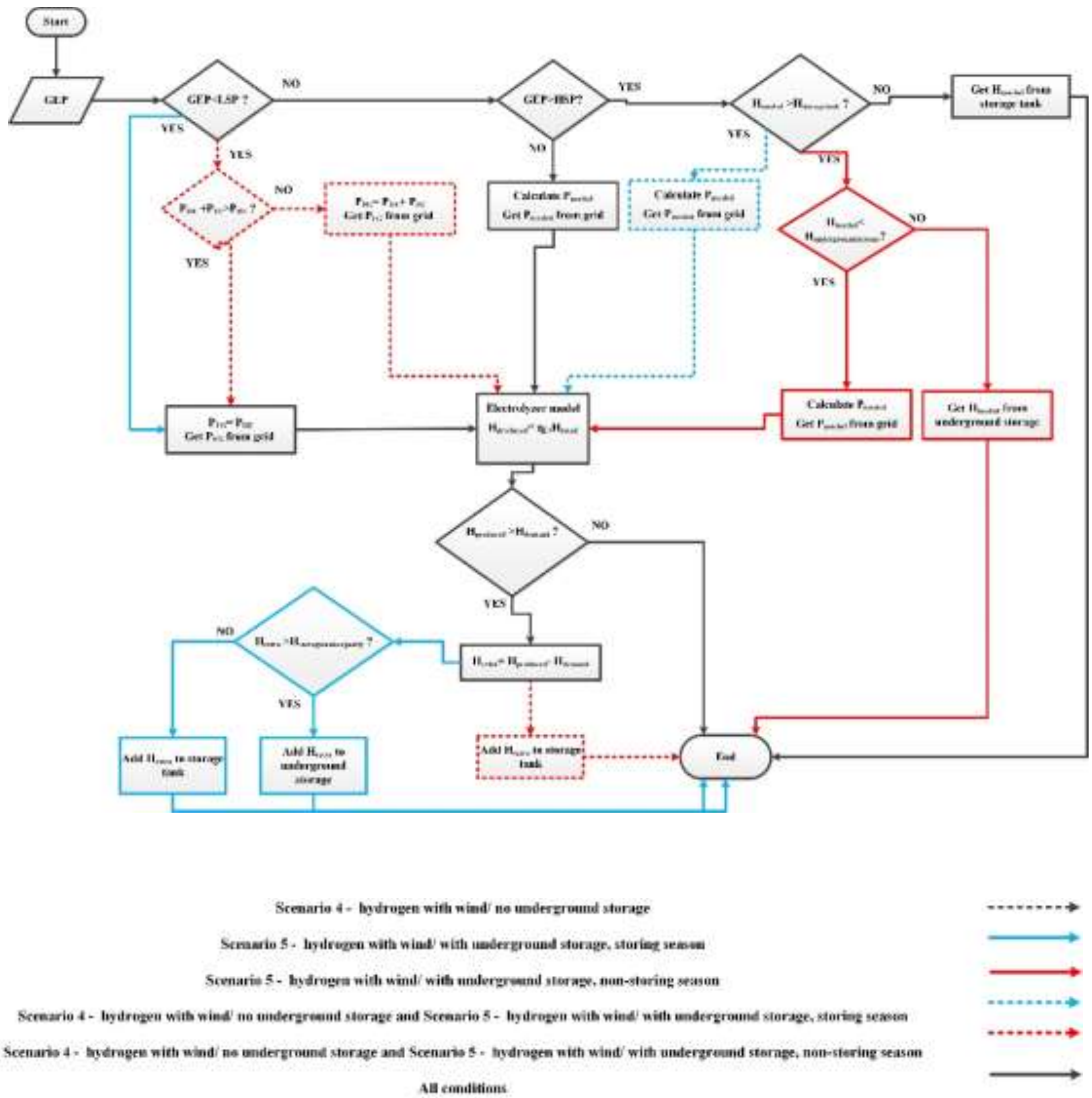
GEP= Grid Electricity Price, LSP= Low Set Price, HSP= High Set Price, P_{DE}= power needed for electrolyzer to meet hydrogen demand, P_{ST}= power needed for electrolyzer to fill the storage tank, P_{EL}= power fed to the electrolyzer, P_{needed}= power bought from the grid, η_E= electrolyzer efficiency, $H_{produced}$= Hydrogen produced by electrolyzer, H_{rated}= Maximum hydrogen production of electrolyzer, H_{demand}=Hydrogen demand, H_{extra}=Hydrogen sent to the storage tank, H_{needed} =Hydrogen from the storage tank

Figure 3-5**.** The simulation logic flowchart of Scenario 2 - Hydrogen with grid/ no underground storage, and Scenario 3 - Hydrogen with grid/ with underground storage

Scenario 3: Hydrogen is produced using grid electricity only, with the option of storing hydrogen underground. The difference between this scenario and the second scenario is that the hydrogen produced when the grid electricity price is lower than 23 CAD per MWh (total accumulated time of about 6 months of the year) is stored in underground storage to be used at times when the price is over 30 CAD per MWh. As a result, the system benefits from a seasonal storage option which enables it to use relatively low cost grid electricity to produce hydrogen that can be used when the grid electricity price is high. This scenario is modeled in two seasons: storing season (shown in Figure 3-6) and non-storing season (shown in Figure 3-7) (Hydrogen with grid/ with underground storage).

In the next 3 scenarios, wind power is used to run the electrolyzer and produce hydrogen. The surplus wind power not used for hydrogen production is sold to the grid. The challenge in using wind power for producing hydrogen is the intermittent nature of wind power while there is a constant demand for hydrogen that needs to be met. To overcome this problem, two solutions are proposed: using large scale storage (explained in scenarios 4 and 5) or using a blend of wind power and grid electricity to produce hydrogen (explained in Scenario 6). These scenarios are appropriate for locations where there is a very large fraction of power is generated from wind power generation capacity.

Scenario 4: An aboveground storage tank is used to supply hydrogen when there is no wind power to produce hydrogen. The minimum size of the storage tank that allows the hub operator to meet the demand can store 2700 kg of hydrogen and is able to provide backup hydrogen for about 14 days. The simulation logic flowchart for this scenario is shown in Figure 3-6. (Hydrogen with wind/ no underground storage).

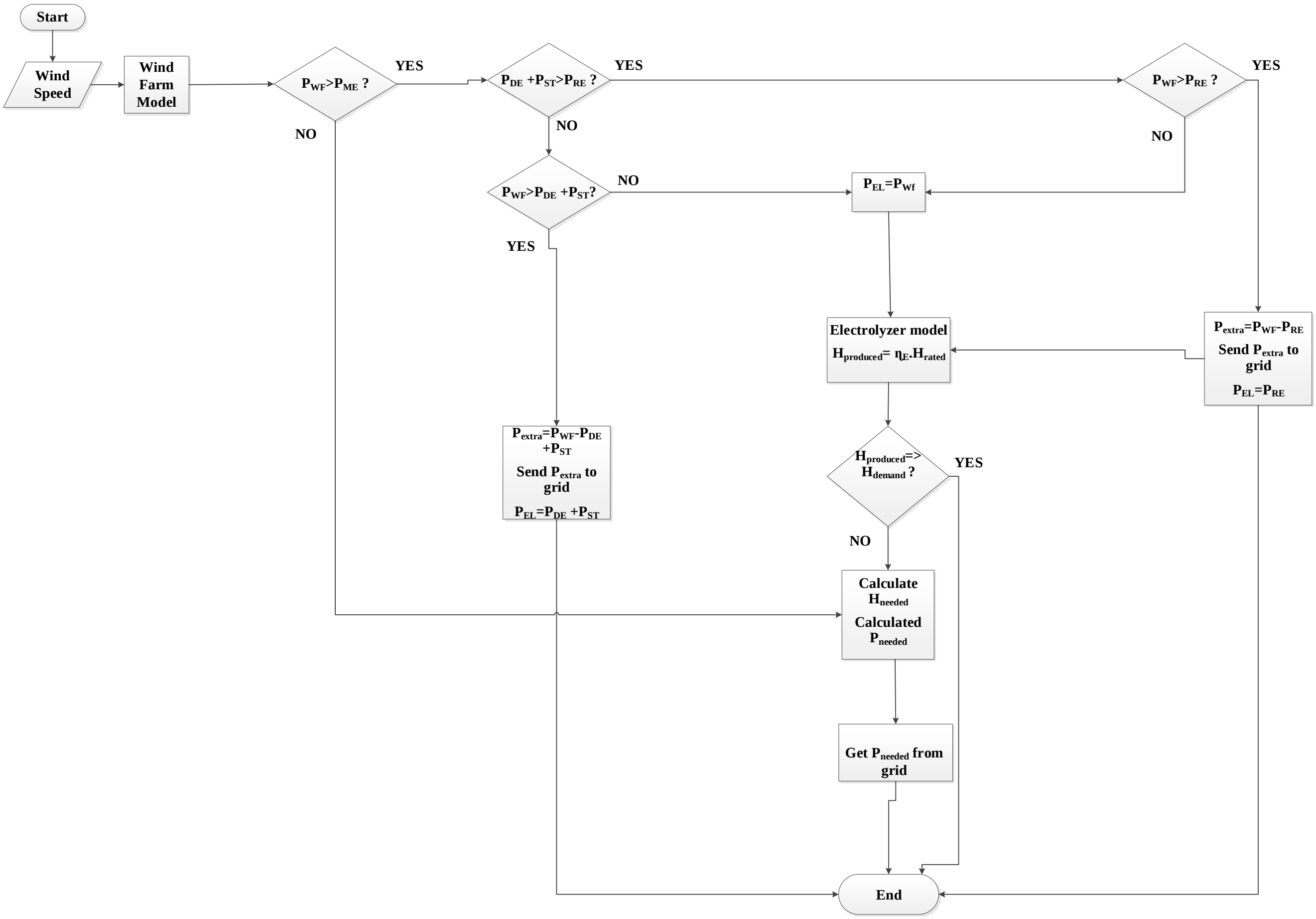


P_{WF}=Power generated by wind farm, P_{ME}=Minimum power of electrolyzer, P_{DE}= power needed for electrolyzer to meet hydrogen demand, P_{ST}= power needed for electrolyzer to fill the storage tank, P_{EL}= power fed to the electrolyzer, P_{extra} = power sold to the grid, η_E= electrolyzer efficiency, $H_{produced}$= Hydrogen produced by electrolyzer, H_{rated}= Maximum hydrogen production of electrolyzer, H_{demand}=Hydrogen demand, H_{extra}=Hydrogen sent to the storage tank, H_{needed} =Hydrogen from the storage tank

Figure 3-6. The simulation logic flowchart of Scenario 4 - Hydrogen with wind/ no underground storage, and Scenario 5 - Hydrogen with wind/ with underground storage

Scenario 5: An underground storage reservoir is used to supply hydrogen when there is no wind power. Hydrogen is produced in the first 6 months of the year as much as possible using wind power and is used in the second 6 months of the year to meet the hydrogen demand when there is no wind power in this period. Although there is a large scale underground hydrogen storage option available in this scenario, an aboveground storage tank with 500 kg hydrogen storage capacity is still needed since the underground storage is only used in the second 6 months of the year. This scenario is modeled in two seasons: storing season and non-storing season shown in Figure 3-6. (Hydrogen with wind/ with underground storage).

Scenario 6: Grid electricity is used to produce hydrogen when there is no wind power available. This system doesn't have any type of storage and electricity is bought from the grid when the wind power is not enough to supply the hydrogen demand. The flowchart for this scenario is shown in Figure 3-7. (Hydrogen with wind and grid blend)



P_{WF}=Power generated by wind farm, P_{ME}=Minimum power of electrolyzer, P_{DE}= power needed for electrolyzer to meet hydrogen demand, P_{ST}= power needed for electrolyzer to fill the storage tank, P_{EL}= power fed to the electrolyzer, P_{extra} = power sold to the grid, P_{needed} = power needed to produce hydrogen when there is not enough wind power, η_E= electrolyzer efficiency, $H_{produced}$= Hydrogen produced by electrolyzer, H_{rated}= Maximum hydrogen production of electrolyzer, H_{demand}=Hydrogen demand, H_{extra}=Hydrogen sent to the storage tank, H_{needed} =Hydrogen from the storage tank

Figure 3-7. The simulation logic flowchart of Scenario 6 - Hydrogen with wind and grid blend

The specifications for each scenario are summarized in Table 3-6.

Table 3-6. Scenarios' specifications

Scenario	**Wind power (MW)**	**Wind farm capacity factor (%)**	**Electrolyzer size (kW)**	**Electrolyzer capacity factor (%)**	**Aboveground storage size (kg of hydrogen)**	**Underground storage size at 8,100 kPa (m^3 of hydrogen)**	**HSP (CAD per MWh)**	**LSP (CAD per MWh)**
Scenario 1 - Wind generation only	18	27	NA	65	NA	NA	NA	NA
Scenario 2 - Hydrogen with grid/ no underground storage	0	NA	885	65	50	0	30	23
Scenario 3 - Hydrogen with grid/ with underground storage	0	NA	885	65	50	67.3×10^6	30	23
Scenario 4 - Hydrogen with wind/ no underground storage	18	27	885	65	2700	0	NA	NA
Scenario 5 - Hydrogen with wind/ with underground storage	18	27	885	65	500	67.3×10^6	NA	NA
Scenario 6 - Hydrogen with wind and grid blend	18	27	885	65	0	0	NA	NA

All models are simulated in a way that all storage elements are empty at the end of the modeling period (one year). In other words, no hydrogen is kept for use in the next year.

3.2.3 Energy hub incentive policies

As mentioned earlier, the government seeks to reduce CO_2 emission: by 1. Incentivizing the generation of renewable energy, and 2. Taxing CO_2 emission via carbon price. A carbon cost (tax or fee associated with a 'cap and trade' program) is defined as the additional cost to firms for CO_2 emissions associated with fossil fuel consumption [58]. This is an indirect method of promoting renewable energy as it doesn't directly allocate subsidies to renewable products, rather it taxes conventional fuels which makes renewable products more competitive. However, there are incentives that directly promote renewable products. These incentives are paid to the renewable energy hub operator in several ways including feed-in tariff (FIT) programs, tax incentives for investments, tradable green certificates (TGC) and capital grants, to name a few.

FIT is a renewable energy incentive policy defined as a payment of a premium price to the generation firms for the renewable energy product generated independently of the spot market price [58]. Two main characteristics of FIT programs are stable, long-term purchase agreements (20 years in this case) and payment levels based on the costs of renewable energy product generation [73].

The advantages of implementing FITs can be summarized as follows [14]:

1. Providing a higher price to the generators to stimulate the increased supply of renewable energy to the grid;
2. Having a flexible system that can be designed for different renewable energy technologies, market structures, locations, and price adjustments, when it is necessary after a fixed period; and
3. Having a secured return over years for investors which will reduce financial risks for the projects to the energy hub operators, making the building of the technology more desirable.

A frequent criticism of FIT programs is that they do not generate sufficient competition [56]. However, Butler et al. [74] showed stronger competition among turbine producers and constructors under FIT than under any other UK renewable energy policies. This is important due to the fact that turbine construction is a stage of the renewable energy value chain, and this competition may have an effect on the final renewable energy price.

Capital grant is defined as monetary assistance granted by a government to an eligible recipient (here renewable energy hub operator) for specific purposes and it doesn't have to be repaid. This kind of incentive may be paid in form of research and development (R&D) grants or covering a part of capital cost (the latter is considered in this study). Capital grant incentives reduce the burden of the initial investment by decreasing equipment costs and addressing market barriers for the investor [14].

For different scenarios, the effect of different incentive programs and their combination is investigated. These programs for different scenarios are as follows.

3.2.3.1 Scenario 1 - Wind generation only

Program 1. Incentivizing wind production with FIT: In this program, the government pays a certain amount of money to the energy hub operator per kWh of wind power sold to the grid. FIT paid to the energy hub operator is the difference between the HOEP and the wind power price that leads to a 7-year payback period for the energy hub operator's investment.

Program 2. Capital grant: In this program, the government pays a capital grant to the energy hub operator to cover part of the capital investment cost. This amount is paid in the first year of the project to cover part of the capital investment of the energy hub operator, so the payback period for the energy hub operator's investment is 7 years. In this program, the government pays no FIT incentive per kWh of wind and the energy hub operator sells wind power to the grid at HOEP.

3.2.3.2 Scenario 2 - Hydrogen with grid/ no underground storage, and Scenario 3 - Hydrogen with grid/ with underground storage

Two incentive programs are investigated in these two scenarios.

Program 1. FIT for hydrogen: In this program, the government pays a certain amount of money to the energy hub operator per kg of hydrogen sold to the consumer. FIT paid to the energy hub operator is the difference between the hydrogen price the consumer is willing to pay to substitute its natural gas consumption (shown in Table 3-3) and the hydrogen price that leads to a 7-year payback period for energy hub operator's investment.

Program 2. Capital grant: In this program, the government pays a capital grant to the energy hub operator to cover part of the capital investment cost. This amount is paid in the first year of the project to cover part of the capital investment of the hub operator, so the payback period for the energy hub operator's investment is 7 years. In this program, the government pays no FIT incentive per kg of hydrogen and the hub operator sells the hydrogen to the consumer at the consumer's desired price (shown in Table 3-3).

3.2.3.3 Scenario 4 - Hydrogen with wind/ no underground storage, Scenario 5 - Hydrogen with wind/ with underground storage, and Scenario 6 - Hydrogen with wind and grid blend

Three incentive programs are investigated in these three scenarios.

Program 1. FIT for wind power and hydrogen: In this program, the government pays a certain amount of money to the energy hub operator for both its products per kg of hydrogen sold to the consumer and per kWh of wind to the grid. The FIT price for each product depends on the FIT price of the other product. In other words, the government pays incentive to a product in such a way that the total profit of the hub operator from both products leads to a 7-year payback period. As a result, if the FIT for one product increases, the FIT for the other product should decrease to keep the payback period to 7 years. The FIT value for hydrogen is calculated with the FIT values of 12, 16 and 20 cents per kWh for wind.

Program 2. FIT for wind power and capital grant: In this program, the hub operator can sell wind power to the grid at a FIT values of 12, 16 and 20 cents per kWh depending on the case. As a result, the government pays an annual amount to the hub operator based on wind power generation. However, the hub operator has to sell hydrogen to the consumer at the consumer's desired price and the government pays no FIT for hydrogen. In addition to the FIT incentive for wind power, government pays capital grant to the hub operator, so the payback period of the investment is 7 years. The amount of the capital grant depends on the FIT value for wind power and consumer's desired hydrogen price.

Program 3. FIT for hydrogen: In this program, the government pays a certain amount of money via a FIT program to the energy hub operator per kg of hydrogen sold to the consumer. The incentive paid to the energy hub operator is calculated based on the hub operator's revenue from selling wind power to the grid at HOEP and guaranteeing a 7-year payback period. The amount of FIT will be the difference between the hydrogen price required to guarantee a 7-year payback period and the consumer's desired price.

Scenarios and programs investigated in each scenario are summarized in Table 3-7.

Table 3-7. Description of the scenarios and the incentive programs in each scenario

Scenario	**Incentive programs**
Scenario 1 - Wind generation only	FIT for wind
	Capital grant
Scenario 2 - Hydrogen with grid/ no underground storage	FIT for hydrogen
	Capital grant
Scenario 3 - Hydrogen with grid/ with underground storage	FIT for hydrogen
	Capital grant
	FIT for wind power and hydrogen

Scenario 4 - Hydrogen with wind/ no underground storage	FIT for wind and capital grant
	FIT for hydrogen
Scenario 5 - Hydrogen with wind/ with underground storage	FIT for wind power and hydrogen
	FIT for wind and capital grant
	FIT for hydrogen
Scenario 6 - Hydrogen with wind and grid blend	FIT for wind power and hydrogen
	FIT for wind and capital grant
	FIT for hydrogen

3.3 Results and discussion

3.3.1 Scenario 1 - Wind generation only

Table 3-8 shows the results for Scenario 1 - wind generation only. In order to have a 7-year payback period for the wind project, the wind power selling price is calculated to be 20 cents per kWh. It is worth mentioning that the grid electricity is a blend of different sources and the lifecycle CO_2 emission is calculated for every hour based on the blend as explained earlier. If the wind energy hub operator only receives the Hourly Ontario Electricity Price (HOEP) price for electricity, then the capital grant program leads to a negative NPV for the investor in this scenario. The negative NPV is due to low selling price of wind power (HOEP) and high annual cost of wind power production. This means the annual profit is negative and no matter how much of the capital investment is covered by incentive, the investment leads to a negative NPV.

Table 3-8. Results for Scenario 1 - Wind generation only (costs are shown over a 20-year period)

Program	Description	Wind price (Cents per kWh)	Annual payment by the government (CAD)	Capital grant by the government (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg)	NPV of the hub operator (CAD)	Capital cost of the hub operator (CAD)	Amount of lifecycle CO_2 prevented to be emitted annually (kg)
1	FIT for wind	20	7,681,674	0	1.343	1.343	34,520,300	38,970,974	2,806,885
2	Capital grant	This program is infeasible because the annual profit (revenue-cost) is not positive							

3.3.2 Scenario 2 - Hydrogen with grid/ no underground storage

Table 3-9 shows the results for Scenario 2 - hydrogen with grid/ no underground storage. In order to have a 7-year payback period, the hydrogen selling price is calculated to be 5.16 CAD per kg in program 1. The amount of money the government pays to the hub operator annually in the form of FIT incentive decreases as the carbon price increases. The reason for this is that as the carbon price increases, energy consumer is willing to pay a higher price for hydrogen. Table 3-9 shows that the FIT program can promote investing in hydrogen infrastructure while capital grant program leads to negative NPV from the investment.

Table 3-9. Results for Scenario 2 - Hydrogen with grid/ no underground storage (costs are shown over 20-year period)

Program	Description	Carbon price (CAD per tonne)	Hydrogen price (CAD per kg)	Annual payment by the government (CAD)	Capital grant by the government (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg)	Capital cost of the hub operator (CAD)	NPV of the hub operator (CAD)	Additional cost of the consumer (CAD)	kg CO_2 prevented to be emitted annually
1	FIT for hydrogen	0	5.13	333,934	0	0.46	0.46	1,224,291	1,084,471	0	349,374
		30	5.13	315,947	0	-1.22	0.44	1,224,291	1,084,471	1,193,126	
		50	5.13	303,956	0	-2.33	0.42	1,224,291	1,084,471	1,988,543	
2	Capital grant	0	0.49	This program is infeasible because the annual profit (revenue-cost) is not positive							
		30	0.74								
		50	0.91								

3.3.3 Scenario 3 - Hydrogen with grid/ with underground storage

Table 3-10 shows the results for Scenario 3 - Hydrogen with grid/ with underground storage. In order to have a 7-year payback period, the hydrogen selling price is calculated to be 5.02 CAD per kg shown in Table 3-10. The FIT program promotes investing in hydrogen infrastructure while capital grant program leads to negative NPV from the investment.

Table 3-10. Results for Scenario 3 - hydrogen with grid/ with underground storage

Program	Description	Carbon price (CAD per tonne)	Hydrogen price (CAD per kg)	Annual payment by the government (CAD)	Capital grant by the government (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg)	Capital cost of the hub operator (CAD)	NPV of the hub operator (CAD)	Additional cost of the consumer (CAD)	Amount of CO_2 prevented to be emitted annually (kg)
1	FIT for hydrogen	0	5.02	325,824	0	0.43	0.43	1,224,291	1,084,471	0	376,016
		30	5.02	307,837	0	-1.16	0.40	1,224,291	1,084,471	1,193,126	
		50	5.02	295,846	0	-2.21	0.39	1,224,291	1,084,471	1,988,543	

2	Capital grant	0	0.49	This case is infeasible because the annual profit (revenue-cost) is not positive
		30	0.74	
		50	0.91	

3.3.4 Scenario 4 - Hydrogen with wind/ no underground storage

Table 3-11 shows the results for Scenario 4 - Hydrogen with wind/ no underground storage. In order to have a 7-year payback period, the hydrogen selling price is calculated based on different wind power selling prices in program 1 as shown in Table 3-12.Table 3-11 shows that for a constant carbon price, both FIT programs (programs 1 & 3) are more expensive for the government than the combination of FIT and capital grant program. The FIT program promotes investment in hydrogen infrastructure as it leads to higher NPV for the energy hub operator. This is because of the high capital cost of wind power infrastructure. However, FIT programs are more effective in promoting renewable energy infrastructure as they lead to higher NPV in comparison with the combination of FIT and capital grant program.

Table 3-11. Results for Scenario 4 - Hydrogen with wind/ no underground storage (costs are shown over 20-year life of the infrastructure)

Program	Description	Carbon price (CAD per tonne)	Wind price (Cents per kWh)	Hydrogen price (CAD per kg)	Annual payment by the government (CAD)	Capital grant by the government (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg)	Capital cost of the hub operator (CAD)	NPV of the hub operator (CAD)	Additional cost of the consumer (CAD)	Amount of CO_2 prevented to be emitted annually (kg)
1	FIT for wind power and hydrogen	0	Shown in Table 3-12	Shown in Table 3-12	8,778,150	0	1.4	1.40	43,925,492	38,908,988	0	3,078,880
		30			8,760,163	0	1.21	1.398	43,925,492	38,908,988	1,193,126	
		50			8,748,172	0	1.08	1.395	43,925,492	38,908,988	1,988,543	
2	FIT for wind and capital grant	0	12	0.49	3,607,378	26,920,950	1.01	1.01	17,004,542	15,062,541	0	3,078,880
			16	0.74	5,094,073	19,180,668	1.12	1.12	24,744,825	21,918,846		
			20	0.91	6,580,768	11,440,385	1.24	1.24	32,485,107	28,775,150		
		30	12	0.49	3,607,378	26,827,304	0.82	1.01	17,098,188	15,145,492	1,193,126	
			16	0.74	5,094,073	19,087,022	0.93	1.12	24,838,471	22,001,797		
			20	0.91	6,580,768	11,346,739	1.04	1.23	32,578,753	28,858,101		

		50	12	0.49	3,607,378	26,764,873	0.69	1.01	17,160,619	15,200,793	1,988,543	
			16	0.74	5,094,073	19,024,591	0.80	1.12	24,900,901	22,057,098		
			20	0.91	6,580,768	11,284,309	0.92	1.23	32,641,184	28,913,402		
3	FIT for hydrogen	0	HOEP	122.38	8,778,150	0	1.4	1.40	43,925,492	38,908,988	0	3,078,880
		30	HOEP	122.38	8,760,163	0	1.21	1.397	43,925,492	38,908,988	1,193,126	
		50	HOEP	122.38	8,748,172	0	1.08	1.395	43,925,492	38,908,988	1,988,543	

Table 3-12. Hydrogen selling price for program 1 of Scenario 4 - Hydrogen with wind/ no underground storage

Wind price (Cents per kWh)	**Hydrogen price (CAD per kg)**
12	72.29
16	51.65
20	31

3.3.5 Scenario 5 - Hydrogen with wind/ with underground storage

Table 3-13 shows the results for Scenario 5 - Hydrogen with wind/ with underground storage. In order to have a 7-year payback period, the hydrogen selling price is calculated based on different wind power selling prices in program 1 as shown in Table 3-14.

Table 3-13 shows that for a constant carbon price, both FIT programs (programs 1 & 3) are more expensive for the government than the capital grant program. The FIT programs promote investing in hydrogen infrastructure more as it leads to higher NPV for the Energy Hub operator. This is similar to the results for Scenario 4.

Table 3-13. Results for Scenario 5 - Hydrogen with wind/ with underground storage

Program	Description	Carbon price (CAD per tonne)	Wind price (Cents per kWh)	Hydrogen price (CAD per kg)	Annual payment by the government (CAD)	Capital grant by the government (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg)	Capital cost of the hub operator (CAD)	NPV of the hub operator (CAD)	Additional cost of the consumer (CAD)	Amount of CO_2 prevented to be emitted annually (kg)
1	FIT for wind power and hydrogen	0	Shown in Table 3-14	Shown in Table 3-14	8,167,643	0	1.30	1.30	40,828,700	36,165,865	0	3,081,885
		30			8,149,656	0	1.11	1.298	40,828,700	36,165,865	1,193,126	

		50			8,137,665	0	0.98	1.296	40,828,700	36,165,865	1,988,543	
2	FIT for wind and capital grant	0	12	0.49	3,606,683	23,746,045	0.96	0.96	17,082,655	15,131,733	0	3,081,885
			16	0.74	5,093,218	16,006,597	1.07	1.07	24,822,103	21,987,299		
			20	0.91	6,579,752	8,267,149	1.18	1.18	32,561,551	28,842,864		
		30	12	0.49	3,606,683	23,652,399	0.77	0.96	17,176,301	15,214,684	1,193,126	
			16	0.74	5,093,218	15,912,951	0.88	1.07	24,915,749	22,070,250		
			20	0.91	6,579,752	8,173,503	0.99	1.18	32,655,197	28,925,815		
		50	12	0.49	3,606,683	23,589,969	0.64	0.96	17,238,732	15,269,985	1,988,543	
			16	0.74	5,093,218	15,850,520	0.751	1.07	24,978,180	22,125,551		
			20	0.91	6,579,752	8,111,072	0.86	1.18	32,717,628	28,981,116		
3	FIT for hydrogen	0	HOEP	113.90	8,167,643	0	1.30	1.30	40,828,700	36,165,865	0	3,081,885
		30	HOEP	113.90	8,149,656	0	1.11	1.298	40,828,700	36,165,865	1,193,126	
		50	HOEP	113.90	8,137,665	0	0.98	1.296	40,828,700	36,165,865	1,988,543	

Table 3-14. Hydrogen selling price for Scenario 5 - Hydrogen with wind/ with underground storage

Wind price (Cents per kWh)	Hydrogen price (CAD per kg)
12	63.82
16	43.18
20	22.54

3.3.6 Scenario 6 - Hydrogen with wind and grid blend

Table 3-15 shows the results for Scenario 6 - Hydrogen with wind and grid blend. In this scenario, about 28% of the power needed to produce hydrogen comes from the grid. In order to have a 7-year payback period, the hydrogen selling price is calculated based on different wind power selling prices in program 1 as shown in Table 3-16.

Table 3-15 shows that for a constant carbon price, both FIT programs (programs 1 & 3) are more expensive for the government than the capital grant program. The FIT programs promote investing in hydrogen infrastructure more as it leads to higher NPV for the Energy Hub operator. This is similar to the results for Scenarios 4 and 5.

Table 3-15. Results for Scenario 6 - Hydrogen with Wind Power and Grid Electricity blend

program	Description	Carbon price (CAD per tonne)	Wind price (Cents per kWh)	Hydrogen price (CAD per kg)	Annual payment by the government (CAD)	Capital grant by the government (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg)	Capital cost of the hub operator (CAD)	NPV of the hub operator (CAD)	Additional cost of the consumer (CAD)	Amount of CO_2 prevented to be emitted annually (kg)
s1	FIT for wind power and hydrogen	0	Shown in Table 3-16	Shown in Table 3-16	8,045,168	0	1.268	1.268	40,124,884	35,542,428	0	3,113,058
		0			8,027,181	0	1.08	1.266	40,124,884	35,542,428	1,193,126	
		0			8,015,190	0	0.95	1.264	40,124,884	35,542,428	1,988,543	
2	FIT for wind and capital grant	0	12	1.35	8,045,168	22,267,180	0.95	0.95	17,857,704	15,818,268	0	3,113,058
			16	2.03	8,027,181	14,230,204	1.07	1.07	25,894,680	22,937,382		
			20	2.48	8,015,190	6,193,229	1.18	0.95	33,931,655	30,056,495		
		30	12	1.35	8,045,168	22,173,534	0.76	0.95	17,951,351	15,901,219	1,193,126	
			16	2.03	8,027,181	14,136,558	0.88	1.06	25,988,326	23,020,333		
			20	2.48	8,015,190	6,099,583	1	0.950	34,025,301	30,139,446		
		50	12	1.35	8,045,168	22,111,103	0.64	0.949	18,013,781	15,956,520	1,988,543	
			16	2.03	8,027,181	14,074,128	0.75	1.06	26,050,756	23,075,634		
			20	2.48	8,015,190	6,037,153	0.86	0.95	34,087,731	30,194,747		
3	FIT for hydrogen	0	HOEP	112.57	8,045,168	0	1.27	1.269	40,124,884	35,542,428	0	3,113,058
		30	HOEP	112.57	8,027,181	0	1.078	1.266	40,124,884	35,542,428	193,126	
		50	HOEP	112.57	8,015,190	0	0.95	1.264	40,124,884	35,542,428	1,988,543	

Table 3-16. Hydrogen selling price for program 1 of Scenario 6 - Hydrogen with wind and electrical grid blend

Wind price (Cents per kWh)	Hydrogen price (CAD per kg)
12	59.88
16	38.44
20	17.01

3.4 Discussion

The most cost-efficient program for the government in each scenario is shown in Table 3-17. The most cost-efficient program in all scenarios is when the carbon price is 50 CAD per tonne of CO_2 emission (except for Scenario 1 - wind generation only where there is no hydrogen production). The additional cost of consumer (revenue of the government) is 1,988,543 CAD in this carbon price. As can be seen in Table 3-17, the most cost-efficient programs for the government are the ones with the capital grant or a combination of FIT and capital grant.

Table 3-17 **.**The most cost-efficient program in each Scenarios

Scenario	Program	Annual payment by the government (CAD)	Capital grant (CAD)	Government's profit (CAD per kg)	Government's expenditure (CAD per kg of CO_2 reduced)	CO_2 reduction (kg)
Scenario 1 - Wind generation only	FIT for wind	7,681,674	0	1.343	1.343	2,806,885
Scenario 2 - Hydrogen with grid/ no underground storage	FIT for hydrogen	303,956	0	-2.33	0.42	349,374
Scenario 3 - Hydrogen with grid/ with underground storage	FIT for hydrogen	295,846	0	-2.21	0.39	376,016
Scenario 4 - Hydrogen with wind/ no underground storage	FIT for wind and capital grant	3,607,378	26,764,873	0.69	1.01	3,078,880
Scenario 5 - Hydrogen with wind/ with underground storage	FIT for wind and capital grant	3,606,683	23,589,969	0.64	0.96	3,081,885

Scenario 6 - Hydrogen with wind and grid blend	FIT for wind and capital grant	8,045,168	22,111,103	0.64	0.949	3,113,058

Table 3-18 shows the results for FIT programs in all Scenarios (program 1 in Scenario 1 - wind generation only, Scenario 2 - hydrogen with grid/ no underground storage and Scenario 3 - hydrogen with grid/ with underground storage and program 1 and 3 in Scenario 4 - Hydrogen with wind/ no underground storage, Scenario 5 - Hydrogen with wind/ with underground storage and Scenario 6 - hydrogen with wind and grid blend).

Table 3-18 **.** FIT programs for all scenarios

Scenario	**Program**	**Annual payment by the government (CAD)**	**CO_2 reduction (kg)**	**Government's expenditure (CAD per kg)**
Scenario 1 - Wind generation only	FIT for wind	7,681,674	2,806,885	1.343
Scenario 2 - Hydrogen with grid/ no underground storage	FIT for hydrogen	303,956	349,374	0.42
Scenario 3 - Hydrogen with grid/ with underground storage	FIT for hydrogen	295,846	376,016	0.39
Scenario 4 - Hydrogen with wind/ no underground storage	FIT for wind power and hydrogen, FIT for hydrogen	8,778,150	3,078,880	1.40
Scenario 5 - Hydrogen with wind/ with underground storage	FIT for wind power and hydrogen, FIT for hydrogen	8,167,643	3,081,885	1.30
Scenario 6 - Hydrogen with wind and grid blend	FIT for wind power and hydrogen, FIT for hydrogen	8,045,168	3,113,058	1.268

The most profitable program for the hub operator in each scenario is shown in Table 3-19.

Table 3-19. The best program for energy hub operator in each scenario

Scenario	Program	Hub operator Investment (CAD)	NPV of energy hub operator (CAD)
Scenario 1 - Wind generation only	FIT for wind	38,970,974	34,520,300
Scenario 2 - Hydrogen with grid/ no underground storage	FIT for hydrogen	1,224,291	1,084,471
Scenario 3 - Hydrogen with grid/ with underground storage	FIT for hydrogen	1,224,291	1,084,471
Scenario 4 - Hydrogen with wind/ no underground storage	FIT for hydrogen, FIT for wind power and hydrogen	43,925,492	38,908,988
Scenario 5 - Hydrogen with wind/ with underground storage	FIT for hydrogen, FIT for wind power and hydrogen	40,828,700	36,165,865
Scenario 6 - Hydrogen with wind and grid blend	FIT for hydrogen, FIT for wind power and hydrogen	40,124,884	35,542,428

Comparing the results for all scenarios and examining Table 3-17, Table 3-18, and Table 3-19 we conclude that:

1. Incentivizing hydrogen production with grid electricity is a more cost-efficient policy for the government than incentivizing wind power alone because of two reasons:

A. Grid electricity in Ontario is already a relatively green grid in terms of CO_2 emission as shown in Figure 3-2. Comparing wind power and hydrogen, wind power is incentivized to offset the grid electricity while hydrogen is incentivized to replace natural gas on an energy content basis. Furthermore, the difference in lifecycle emission is higher in the latter. Lifecycle CO_2 emission of wind power is 14 gr of CO_2 per kWh, while the average CO_2 emission for grid electricity in Ontario is 77.71 gr of CO_2 per kWh. These numbers mean that by offsetting 1 kWh of grid electricity with wind power, there is a 63.71 gr of CO_2 emission reduction. Lifecycle CO_2 emission per kWh of natural gas, including both burning and emission, is 235 gr of CO_2 per kWh calculated in Table 3-20.

Table 3-20. Assumed lifecycle CO_2 emission from natural gas combustion

Source	Production	Burning	Sum (gr of CO_2 emission per MJ)	Sum (gr of CO_2 emission per kWh)
grams of CO_2 emission per MJ of NG	13.5 [75]	52.08	65.58	235

Lifecycle emission from burning hydrogen is 145 gr of CO_2 per kWh of hydrogen when hydrogen is produced using grid electricity (using an overall average grid emission factor), and 31 gr of CO_2 per kWh of hydrogen when wind power is used to produce hydrogen. These values are calculated based on 71 kWh of electricity consumption for producing each kg of hydrogen as shown in Table 3-21.

Table 3-21. CO_2 emission for hydrogen production

Source	Electricity	Electrolyzer	Storage	Sum
gr of CO_2 emission per kg of hydrogen using grid electricity	5517.41	43 [76]	170 [76]	5730.41
gr of CO_2 emission per kg of hydrogen using wind power	994	43 [76]	170 [76]	1207

Burning hydrogen has no CO_2 emissions. Substituting each kWh of natural gas with hydrogen produced by grid electricity reduces 90 gr of CO_2 emission which is about 40% higher than the value obtained by replacing grid electricity with wind power. Substituting each kWh of natural gas with hydrogen produced by wind power reduces 204 gr of CO_2 emission which is more than 3 times higher than the value for replacing grid electricity with wind power.

B. HOEP is about 21 CAD per MWh of energy. The hydrogen is produced using grid electricity has a levelized cost of 0.091 and 0.088 CAD per kWh in Scenario 2 - hydrogen with grid/ no underground storage and Scenario 3 - hydrogen with grid/ with underground storage, respectively (shown in Table 3-22). Levelized cost of wind power is 0.12 CAD per kWh.

Table 3-22. Levelized cost of hydrogen in different scenarios

Scenario number	**Levelized cost of hydrogen (CAD per kg) i.e. Operation cost of production**	**Levelized cost of hydrogen energy (HHV) (CAD per kWh)**
Scenario 2 - Hydrogen with grid/ no underground storage	3.60	0.091
Scenario 3 - Hydrogen with grid/ with underground storage	3.48	0.088
Scenario 4 - Hydrogen with wind/ no underground storage	16.49	0.417
Scenario 5 - Hydrogen with wind/ with underground storage	11.87	0.3
Scenario 6 - Hydrogen with wind and grid blend	8.01	0.203

Therefore, not only the production cost of each kWh of hydrogen is lower than the production cost of each kWh of wind, but also each kWh of hydrogen can reduce more CO_2 emission compared to each kWh of wind power. As a result, incentivizing hydrogen production with grid electricity is a more cost-effective policy for the government than an incentive for wind power. The same conclusion, however, can't be drawn by comparing Scenario 1 (wind generation only) with hydrogen production with wind power scenarios (i.e., Scenario 4 - Hydrogen with wind/ no underground storage, Scenario 5 - Hydrogen with wind/ with underground storage, Scenario 6 - Hydrogen with wind and grid blend). This is due to the higher levelized cost of hydrogen when hydrogen is produced using wind power (i.e. cost of the wind power itself). Considering FIT program for all scenarios (shown in Table 3-18), it can be seen that Scenario 5- hydrogen with wind/ with underground storage, Scenario 6 - hydrogen with wind and grid blend are more cost-effective for the government than Scenario 1 - wind generation only. However, hydrogen production using wind power without underground storage is more expensive than wind generation only.

2. Using underground seasonal storage is advantageous for the government as it leads to paying less incentive per kg of CO_2 emission reduction because of two main reasons:

A. Underground storage leads to a lower levelized cost of hydrogen. Underground hydrogen storage provides the option of producing hydrogen when there is no demand and saving it for later use when there is a demand. In hydrogen production with grid electricity Scenarios (Scenario 2 - hydrogen with grid/ no underground storage, and Scenario 3 - Hydrogen with grid/ with underground storage), hydrogen can be produced when the electricity price is low and stored in the underground storage reservoir. The stored hydrogen can be used later on to meet the demand and to prevent the need to produce hydrogen when the gird electricity price is high. Considering the fact that using underground storage only imposes compression operating cost to the system, the levelized cost of hydrogen decreases. In hydrogen production with wind power scenarios (Scenario 4 - Hydrogen with wind/ no underground storage, Scenario 5 - Hydrogen with wind/ with underground storage, and Scenario 6 - Hydrogen with wind and grid blend), there is always the issue of wind power intermittency. To address this issue, large storage elements have to be added to the system. These storage elements can be aboveground storage tanks or a combination of aboveground storage tanks and underground storage reservoirs. The latter, however, has a lower capital cost and as a result leads to lower levelized cost of hydrogen. Comparing different scenarios under the same FIT incentive scheme shown in Table 3-18 shows that Scenario 1- wind generation only is more cost-effective for the government than producing hydrogen using wind power without underground storage. This is due to the high levelized cost of hydrogen. Adding underground storage to the system makes it more cost-effective than Scenario 1 - wind generation only as it reduces levelized cost of hydrogen.

B. Underground storage leads to higher carbon emission reduction. As mentioned earlier, the emission factor of the grid is lower when HOEP is lower than when HOEP is high. Underground storage allows using grid electricity when HOEP is low to produce hydrogen. The aforementioned leads to lower lifecycle CO_2 emission due to using grid electricity which in turn lowers lifecycle CO_2 emission.

As a result, it can be concluded that underground hydrogen storage not only decreases incentives paid by the government, but is also effective in reducing more CO_2 emission. There is however, a difference between the effect of underground storage in using grid power for producing hydrogen (Scenario 2 - Hydrogen with grid/ no underground storage and Scenario 3 - Hydrogen with grid/ with underground storage) and using wind power for producing hydrogen scenarios

(Scenario 4 - Hydrogen with wind/ no underground storage, Scenario 5 - Hydrogen with wind/ with underground storage). In grid scenarios, the NPV in both with and without underground scenarios was the same because the capital cost was the same in both scenarios and the government simply paid more incentive in Scenario 2 - Hydrogen with grid/ no underground storage which led to equal cash flow for the hub operator and as a result, equal NPV. However, in wind only scenarios, the NPV is different because the aboveground storage size is different and this leads to a lower capital cost in Scenario 5 - Hydrogen with wind/ with underground storage). As a result, the amount of incentive paid by the government is different in the two scenarios and different capital costs and cash flows lead to different NPVs.

3. A combination of capital grant and FIT is a more cost-efficient incentive program for the government than FIT only programs. However, FIT programs are more effective for promoting renewable energy in all scenarios as they lead to higher NPVs and are the only programs that lead to positive NPV for the hub operator in some scenarios (Scenario 1 - wind generation only, Scenario 2 - hydrogen with grid/ no underground storage and Scenario 3 - hydrogen with grid/ with underground storage). Capital grant schemes in those scenarios lead to negative NPVs for the hub operator.

4. By increasing the carbon price, the government tends to support renewable energy more, however, it should be noted that this increase will affect the operational cost of energy consumers such as industries. This not only affects the final product cost, but may also lead the industries to leave a province/country, and this, in turn, will affect other areas such as job market. Investigating this effect of other difficult to quantify or assess metrics may be the focus for future work.

5. There is a significant difference between the consumer hydrogen price and hydrogen price that leads to a 7 year payback period for the investor when wind power is used to produce hydrogen (compare values in Table 3-3 with values in Table 3-12, Table 3-14, and Table 3-16. This difference is due to the high capital investment needed for wind infrastructure. As shown in Table 3-22, the levelized cost of hydrogen produced with wind power is considerably higher than the levelized cost of hydrogen produced with grid power which imposes a challenge in the development of hydrogen infrastructure in the context of a stand-alone microgrid.

3.5 Conclusion

This study focuses on the analysis of the various stakeholders' (including the government, the energy hub operator and the energy consumer) advantages in interaction in the context of a microgrid. For successful implementation of renewable technologies, all stakeholders must individually achieve their objectives or some benefit. Unlike previous studies in which the advantages of all stakeholders are confounded, this study analyzes the motivations of each stakeholder independently. The basis for this innovation is the independence of motivation of each stakeholder in an energy system from other stakeholders' motivations. This study also seeks to examine the potential for hydrogen energy storage within a microgrid, as well as examines how different incentives contribute to the perceived viability of a microgrid project.

The results of this study show that for the same incentive policy, incentivizing hydrogen production with grid electricity is the most cost-efficient option for government. While hydrogen production using grid electricity was shown to be a promising method to reduce emissions, hydrogen production using wind power and generating wind power alone are more expensive options for the government to promote due to the high capital cost of wind infrastructure.

From the energy hub operator's point of view, however, incentivizing wind power is a more profitable measure than hydrogen production with grid electricity as it leads to higher NPV. It was also shown that a combination of feed-in tariff (FIT) and capital grant is the most cost-efficient program for the government to pursue from their perspective. FIT programs; however, lead to higher NPVs for the hub operator and as a result, are more profitable for them. This finding agrees with previous reports in the literature. However, capital grant only programs will not be beneficial for the development of renewable energy infrastructure as NPV from the investment is negative when the only incentive scheme in place is capital grant. Results also show that adding underground hydrogen storage to the system provides advantage for the government as it not only reduces levelized cost of hydrogen but also leads to higher CO_2 emission reduction.

In this study, the interaction of three stakeholders in a microgrid was investigated in a deterministic approach. Optimization methodologies will be applied to find the optimal incentive and policy approaches for society as a whole in order to encourage the implementation of distributed energy generation and storage technologies by ensuring that each stakeholder in the microgrid experiences some benefit. Considering the current Ontario electricity mix, hydrogen production with an underground storage option provides a viable option to move toward CO_2 emission reduction goals. In future work, other technologies like solar PV will also be investigated in this matter.

4 Co-benefit analysis of incentives for energy generation and storage systems; a multi-stakeholder perspective

The following section is based on work by Haghi et.al [12], published in the International Journal of Hydrogen Energy. Contribution of authors is detailed in the Statement of Contributions section.

4.1 Introduction

Reducing greenhouse gas (GHG) emissions is an important agenda for countries all over the world. Incentives and support programs for renewable energy technologies have a common goal of reducing GHG emissions and diversifying the energy supply mix. However, the effect of these programs are not limited to diversifying supply mix and GHG emission reduction. Local economic development, job creation, and reduction in health impacts associated with the energy sector are among other motivations for increased support for the development of renewable energies [77].

Ontario pursued a policy toward emission reduction in the electricity sector which included phasing out Ontario's coal power plants and introducing renewable power generation technologies to the grid. Emissions from the electricity sector in Ontario dropped from about 35 Megatonnes of CO_2 equivalent (CO_{2e}) in 2004 to 10.9 Megatonnes of CO_{2e} in 2013 as a result of those policies [4]. Table 4-1 shows Ontario's GHG emission by sector in 1990, 2007, and 2013. Table 4-1 shows that the emission from the electricity sector has decreased 67% between 2007 and 2013.

Table 4-1. Ontario GHG emission by sector in 1990, 2007, and 2013 [4]

Year / Sector	GHG emission in 1990 (Mt CO_{2e})	GHG emission in 2007 (Mt CO2e)	GHG emission in 2013 (Mt CO_{2e})	% change 1990-2013	% change 2007-2013
Transportation	45.9	58.9	60.2	31%	2%
Industry	64.2	60.3	47.7	-26%	-21%
Buildings	27.9	33.4	32.6	17%	-2%
Electricity	25.8	32.9	10.9	-58%	-67%
Agriculture	11	10.5	10	-9%	-5%

Waste	7.5	9.6	9	20%	-6%
Total	182	205.5	171	-6%	-17%

Although Ontario has been able to reduce emissions from its electricity sector, GHG emission from the transportation sector and the building sector has stayed almost the same as shown in Table 4-1. Figure 4-1 shows the GHG emission in Ontario by sector in 2013. As can be seen, transportation, industry, and buildings are the top three GHG emitter sectors in Ontario.

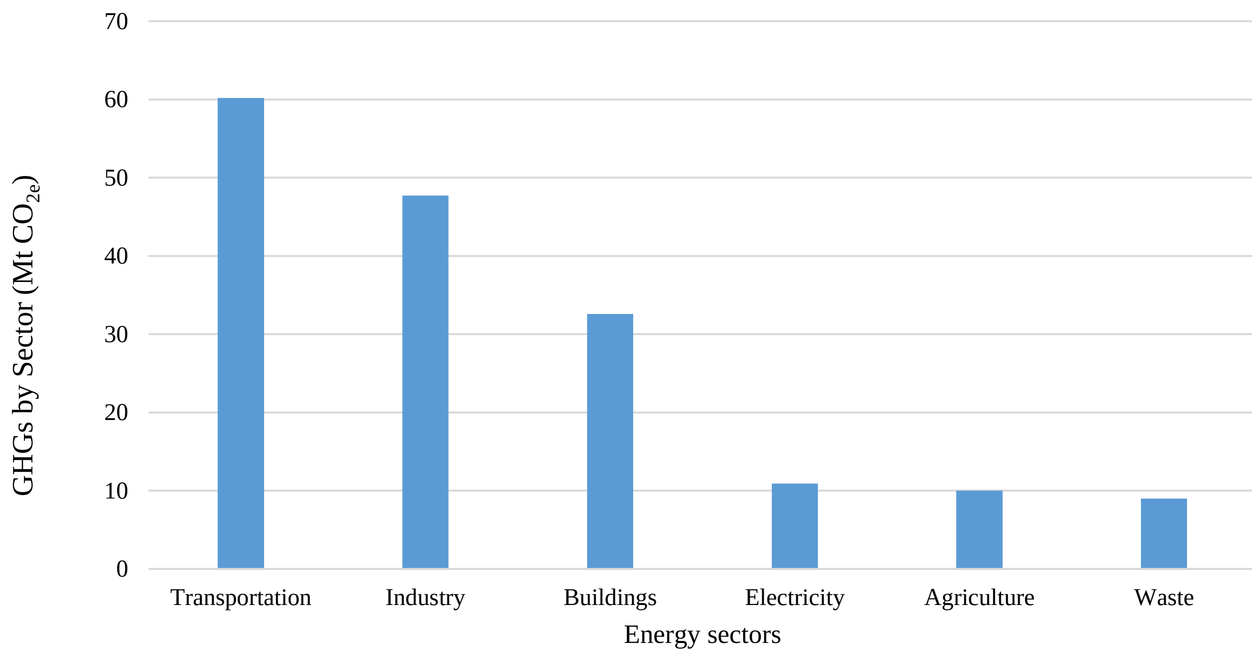


Figure 4-1. GHG emissions by sector in Ontario in 2013 [4]

Figure 4-2 shows the GHG emissions percentage by sector in Ontario in 2013. As can be seen, the transportation and the industry sector accounted more than 60% of emissions in Ontario in 2013.

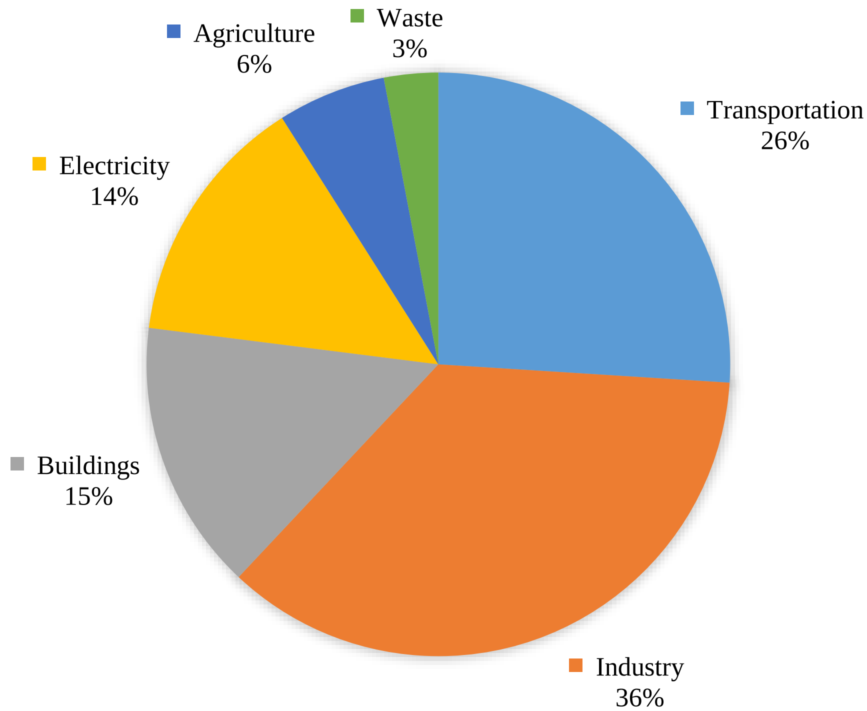


Figure 4-2. GHG emissions percentage by sector in Ontario in 2013 [4]

Renewable generation technologies have been recognized as a viable alternative for renewing Ontario's generation capacity [78]. Table 4-2 shows the newly commissioned generation capacity of 20 MW or more of wind and solar plants in Ontario from 2009 to 2017. As can be seen in Table 4-2, wind and solar generation capacity has increased each year from 2009 to 2017 (except for 2012).

Table 4-2. New commissioned generation capacity of 20 MW or more of wind and solar plants in Ontario [79]

Year	**New wind power capacity (MW)**	**New solar power capacity (MW)**	**Total new capacity (MW)**
2009	380	0	380
2010	200	0	200
2011	227	0	227
2012	0	0	0
2013	215	0	215
2014	719	30	749
2015	879.3	200	1079.3

2016	199	40	239
2017	290	100	390

The investment in renewable electricity generation as well as phasing out coal power plants in Ontario has led to a 95% emission-free electricity generation mix. Figure 4-3 shows the electricity supply mix in Ontario in 2017.

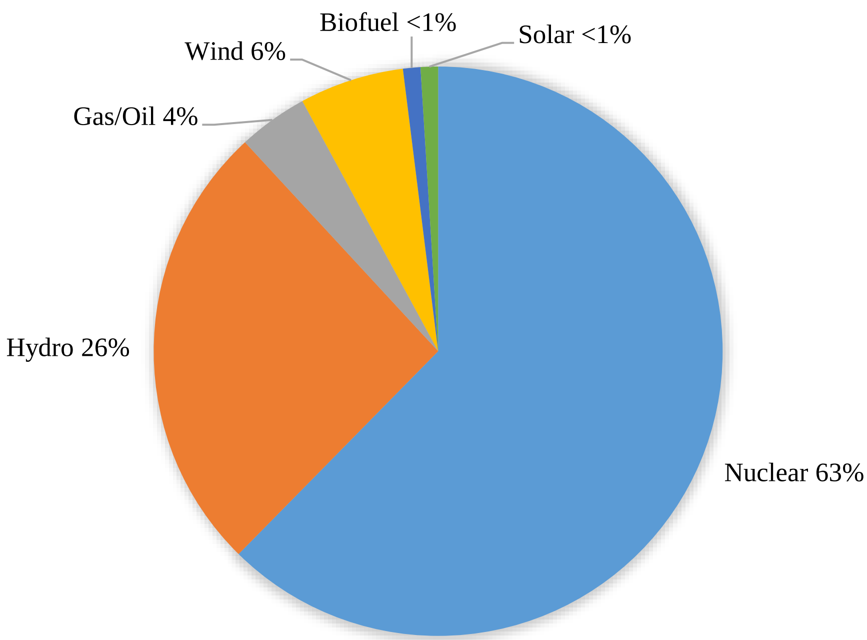


Figure 4-3. 2017 Ontario electricity supply mix [79]

With increasing renewable power generation and decreasing electricity demand, Ontario is experiencing hours with surplus electricity generation. Surplus baseload generation (SBG) in Ontario happens when the sum of generation from nuclear plants, baseload hydropower plants, and wind and solar plants exceeds the demand in the province [80]. Surplus baseload generation in Ontario is managed via export to neighboring jurisdictions or curtailing power [80]. Table 4-3 shows SBG in Ontario as a percentage of net demand.

Table 4-3. SBG as a percentage of Ontario's net demand [80]

Year	Surplus baseload generation as a percentage of demand
2016	9%
2017	7%
2020	6%
2025	1%
2030	2%
2035	2%

The point to note in Table 4-3 is that even in 2030 and 2035 when the SBG is expected to be only 2% of the demand, it will be around 2.7 TWh in a year (assuming the 2016 demand [81]). In addition to the power export, Ontario also curtails power in the forms of solar panel shutoff, wind curtailment, nuclear maneuvering, and hydro spill. The curtailment in Ontario was estimated to be around 2 TWh in 2016 [82].

Based on the available data, it can be concluded that Ontario has a noticeable amount of surplus power available which can be used for electrifying different energy sectors in the province. As 95% of the electricity generated in Ontario is generated with emission-free resources, Ontario's electricity has an advantage for reducing emissions in the transportation and industry sectors. Power-to-Gas, as well as battery-powered and fuel cell-powered forklifts, are technologies that can be utilized in reducing GHG emissions in the industry sector using Ontario's grid power.

4.1.1 Power-to-Gas technology

Electricity grids with low penetration of renewable energies may not need storage technologies to meet the demand. At the same time, the balance between electricity supply and demand will not be seriously affected by limited renewable energy penetration in the grid. However, power curtailment for grid stability will be unavoidable when the penetration of renewable energies increases to a point where generation exceeds the demand, and seasonal storage technologies are necessary for renewable energy penetration of more than 80% [83]. Storage systems can reduce the power curtailed and the need for using peak power plants. Hydrogen energy storage can contribute to the flexibility of the electricity system and control the fluctuation of the intermittent energy sources [84]. Hydrogen as an energy carrier can be used for seasonal energy storage to store large amounts of power for long durations of time [16]. Hydrogen can be used both as a fuel for meeting heat and electricity demands and also as a storage medium for balancing the introduction of renewable energy technologies [85]. Hydrogen is also considered as a viable option for transportation applications and renewable heating [86], [87].

An application of hydrogen is in producing hydrogen-enriched natural gas (HENG) which can be used in natural gas applications with lower emissions. While HENG is recognized as an immediate way to use hydrogen to reduce emissions, it can also be considered as a mediator for moving toward energy systems with pure hydrogen applications [88]. At the same time, hydrogen can act as a link between electricity and natural gas sectors. The systems which use this concept to operate are called Power-to-Gas systems. Figure 3-1 shows the concept block diagram of a Power-to-Gas system.

Power-to-Gas can be used both as a mid-term and a long-term energy storage option [89]. This advantage of Power-to-Gas has been noted in the literature. For instance, Walker et al. [90] stated that Power-to-Gas has advantages in criteria such as energy portability, energy density and the ability for seasonal storage over other storage technologies when utility-scale storage is considered. Another advantage of implementing a Power-to-Gas system is that it enables the hydrogen use where we want it, when we want it, and how we want it. For instance, a Power-to-Gas system can be used to produce synthetic methane. Estermann et al. [91] analyzed the feasibility of using Power-to-Gas systems for using excess solar power and CO_2 to produce synthetic methane in Germany. These advantages have led to an increase in the number of Power-to-Gas pilot plants that use intermittent power for injecting hydrogen into the natural gas pipelines in different countries in recent years [92]. Putting facts together, Power-to-Gas seems a promising option for Ontario considering all the emission-free power available and the widespread use of natural gas in the province. In this study, we are analyzing the cost-efficiency of investing in Power-to-Gas for reducing GHG emissions. We are also comparing that criteria with other renewable generation and storage technologies.

4.1.2 Battery-powered and fuel cell-powered forklifts

Forklifts are classified into LPG, diesel, battery-powered, and fuel cell-powered forklifts based on their powertrain system. Traditionally, diesel forklifts have been a favorite choice because of their unique characteristics such as durability [93]. However, this favorability has changed over the years, and electric forklifts have been chosen more often due to their zero on-site emission and low noise pollution [93]. These characteristics are shared between battery-powered forklifts and fuel cell-powered forklifts which have been a focus of research and development in recent years [94].

Battery-powered and fuel cell-powered forklifts have a potential for reducing GHG emissions by replacing the consumption of fossil fuels with electricity. A report by Toyota [95] claims that electric forklifts have a significantly lower level of emissions than internal combustion engine forklifts. Elgowainy et al. [96] also stated that replacing internal combustion engine (ICE) forklifts with fuel cell-powered forklifts has a great potential in reducing GHG emissions. This potential, however, depends on the emissions associated with the electricity generated and the hydrogen produced for use in the forklifts. In that sense, Ontario's emission-free electricity mix and the available surplus is a promising option for fueling battery-powered and fuel cell-powered forklifts for replacing diesel forklifts.

Although battery-powered forklifts need less expensive infrastructure to refuel, the lower cost of refueling and maintenance of fuel cell-powered forklifts gives them an advantage [97]. Reviewing the literature focusing on comparing fuel cell-powered forklifts and battery-powered forklifts doesn't lead to a uniform conclusion. A report by U.S Department of Energy [98], shows that fuel cell-powered forklifts have a lower annual cost of ownership compared to battery-powered forklifts. Renquist et al. [99] however, showed that the cost advantage of fuel cell-powered and battery-powered forklifts depends on the workload of the forklifts. Battery-powered forklifts have lower costs for low workload applications while fuel cell-powered forklifts have an economic advantage in higher workload applications. This study aims at comparing the cost-effectiveness of battery-powered and fuel cell-powered forklifts in reducing GHG emissions.

4.1.3 Literature review of energy incentives

A gaps in research related to energy incentives is the limited scope of the analysis to some stakeholders in an energy system and not all of them. The research in the area of energy policy and energy incentives is often limited to two main areas:

1. How successful the incentive programs are in achieving their designed goals?
2. How profitable is it to invest in renewable energy technologies under an incentive program?

Niesten et al. [100], analyzed the types of firms that invest in the production of Dutch onshore wind energy under certain policy schemes. The authors argued that policy schemes affect factors such as the risk of investment and expected returns on investment which influence the amount and type of investments in the wind energy. Chang et al. [101], assessed the efficiency of policies in achieving the intended goals using criteria of the market, uncertainty, profitability, technology, and financial resources criteria. The authors used the criteria to build an index to evaluate the policies. Palmer and Burtraw [102], assessed the cost-efficiency of the renewable portfolio standard in increasing the contribution of renewables to the total U.S. electricity supply. Bean et al. [103], used a cost-benefit approach to assess the efficiency of wind policy schemes including investment credit, feed-in tariffs, and feed-in premiums. Falconett and Nagasaka [56], assessed the financial return and profitability of renewable energy projects (small-scale hydroelectric, wind energy and solar PV) under different renewable energy support mechanisms. The authors in [56], found that feed-in tariff is the most effective policy for reducing the profitability of wind and solar projects. However, hydropower was favored under a green certificate program.

An important factor in the design of renewable energy policies is the effect of those policies and subsequent changes to the energy system on energy consumers. In this study, we examine the externalities of energy incentives including their health impacts and their effect on economic development. We also include the objectives of energy consumers in analyzing the cost-effectiveness of energy incentives designed by the government. In this study, we are considering two types of energy incentives. The first type is focused on incentivizing renewable energy generation technologies which will increase the share of renewable energies in the electricity system. The second type of energy incentives considered in this study is for technologies and systems which use electricity to replace fossil fuels in other sectors of energy systems such as the transportation, residential and industrial sectors. The renewable energy technologies considered in this study include wind and solar power technologies, Power-to-Gas system and battery-powered and fuel cell-powered forklifts.

Multiple pieces of research have been focused on analyzing the energy incentives for the deployment of wind and solar systems, however, the research focusing on the analysis of incentives on the development of hydrogen infrastructure is very limited in the literature. Incentives and support policies are important for the initial development of hydrogen energy systems. This point has been noticed by different researchers. Alanne and Cao [104], stated that analyzing business models, incentives, as well as energy policies, are important for the development of hydrogen energy systems besides the required technological innovations. Similarly, Marino et al. [105], stated that incentives are essential for the development of hydrogen energy systems. As mentioned earlier, however, literature in the area of incentives for hydrogen systems is limited. For instance, while Perera et al. [106], stated that hydrogen vehicles and hydrogen use in residential applications are promising options in some Canadian provinces such as Alberta, Nova Scotia, and Saskatchewan, their analysis didn't include such technologies due to lack of available data. Similarly, although Apak et al. [107], pointed to the essential role of financial incentives in the development of hydrogen infrastructure, they didn't do any calculations to show the cost-efficiency of such incentives. Olateju et al. [49], also stated that the feed-in tariffs for renewable generation power increase the hydrogen cost competitiveness of wind and hydrogen hybrid systems. The analysis of incentives, however, was limited to this conclusion. Marino et al. [105], investigated the effect of incentives on hybrid energy systems using hydrogen as a storage means. Their analysis was limited to solar/hydrogen hybrid and solar/wind/hydrogen hybrid systems used in residential applications.

Based on the literature review and the gaps found in the literature in the area of energy incentives and hydrogen energy systems, the contribution of this study can be summarized as the following:

1. Considering the advantages of all stakeholders in an energy system rather than only one of them in analyzing the cost-efficiency of energy incentives;
2. Considering the externalities of energy incentives in assessing the efficiency of incentives in reducing GHG emissions;
3. Assessing the cost-efficiency of Power-to-Gas, fuel cell-powered forklift, and battery-powered forklifts in reducing GHG emissions;

4. Comparing battery and hydrogen storage technologies as competing as well as complementary technologies in reducing GHG emissions in Ontario; and

5. Comparing the cost-efficiency of energy generation and energy storage technologies in reducing GHG emissions.

The results of the models developed in this study provide a better understating of the effect of energy policies not only on the development of renewable infrastructure but also on health impacts and profitability of firms investing in or using renewable technologies.

4.2 Methodology

In this study, we aim to investigate the objectives of all three stakeholders (the government, the energy hub operator, and energy consumers) in an energy system. Figure 4-4 shows the interaction of the three stakeholders considered in this study.

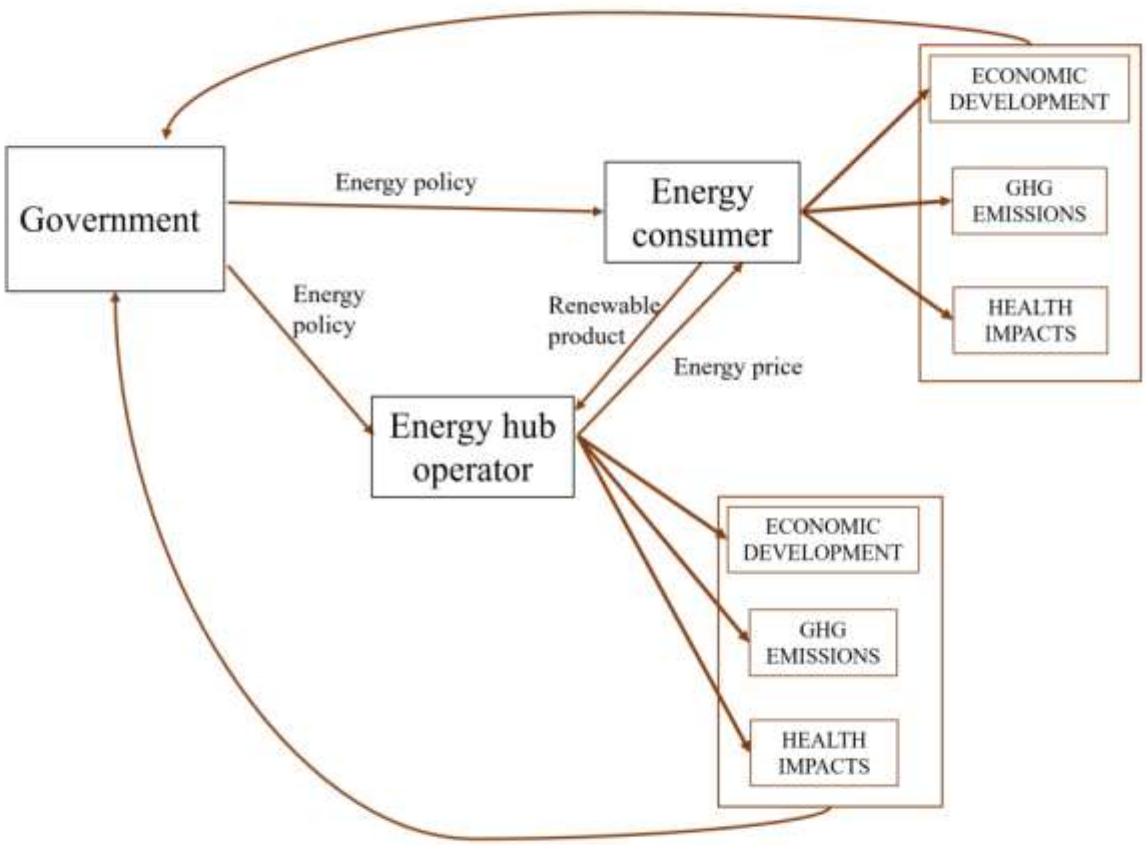


Figure 4-4. Interaction of stakeholders in an energy system

To better reflect the objectives of all stakeholders, the externalities of energy policy schemes including their effect on health impacts and the taxes the government receives are considered in this study.

4.2.1 Health impacts

Airborne pollutants associated with fossil fuels have great impacts on the health of a country/jurisdiction. The health and social costs related to these health impacts can be in the order of billions of dollars each year [108]. Carbon monoxide (CO), particulate matter (PMx), nitrogen oxide (NOx), or sulfur oxide (SOx) are pollutants with immediate and long-term detrimental effects on health which include mortality, hospital admissions, emergency room visits for asthma, bronchitis, lung cancer, and heart diseases [108]. Lowering GHG emissions can reduce financial costs and disease rates and increase life expectancy and productivity [108].

Calculating the specific health impacts associated with natural gas and diesel fuel consumption is not within the scope of this work. Alternatively, we used values available in the literature to estimate the health impacts associated with the use of fossil fuels in our scenarios. The pollutants considered in this study are PM2.5, SOx, NOx, and CO. The health impacts costs associated with these pollutants are shown in Table 4-4.

Table 4-4. Unit cost of pollutants [109]

Pollutant	PM2.5	SOx	NOx	CO
Unit Costs of pollutants (2017 CAD per tonne)	9244	3572	15126	2017

4.2.2 Taxes

Taxes received by the government from the energy hub operator and the energy consumer are considered as a scale to measure the effect of the energy incentives schemes on the portability of the energy hub operator and the energy consumer. We are assuming that the government taxes the businesses (both the energy hub operator and the energy consumer) based on their profit. The tax rate considered in this study is 10%. The 10% tax is applied after subtracting the annual cost outflow and depreciation cost from the revenue inflow as shown in Equation 4-1. When energy consumers go under a renewable energy policy, they have to pay more for their energy consumption. We are assuming that the energy consumer's revenue doesn't change which means the consumer pays lower taxes because of their increased cost.

$$Annual\ tax = 0.1 \times (revenue\ inflow - annual\ cost\ overflow - depreciation\ cost) \quad 4\text{-}1$$

4.2.3 Stakeholders

The objectives of the government, the energy hub operator and the energy consumer are explained in details in the following.

Government: The government designs energy and emission policies to reduce GHG emissions associated with the consumption of fossil fuels. The incentive considered in this study is in the form of a capital incentive paid to the energy hub operator (energy investor) at the beginning of the projects. We also assume that the government is responsible and pays for health impacts. The government also collects profit taxes from both the energy hub operator and the energy consumer. The objective of the government is to minimize the amount of money spent per unit of GHG emissions reduction considering the externalities of the energy incentive. Equation 4-2 shows the government's objective function.

$$\begin{aligned} &Government's\ objective \\ &= Min\ (spending\ per\ tonne\ of\ GHG\ emission\ reduction) \\ &= \left(\frac{incentives\ paid \pm taxes\ recived\ or\ lost - health\ impacts\ avoided}{saved\ GHG\ emissions}\right) \end{aligned} \quad 4\text{-}2$$

Energy hub operator (Energy investor): The energy hub operator invests in renewable energy infrastructure and operates the system. The revenue for the energy hub operator is the sum of the revenue from selling the renewable product to the energy consumer and the incentives received from the government. By generating renewable products, the energy hub operator contributes to GHG emission and health impact reduction while promoting economic development by paying profit taxes to the government. The objective of the energy hub operator is to maximize profit from investing in renewable energy infrastructure. Equation 4-3 shows the energy hub operator's objective function.

$$Energy\ hub\ operator's objective = Max(NPV\ from\ investment) \quad 4\text{-}3$$
$$= \sum_{t=1}^{T} \left(\frac{(annual\ revenue)_t - (annual\ cost)_t}{(1+r)^t}\right.$$
$$\left. - (investment\ cost - government\ incentive)\right)$$

In Equation 4-3, NPV of the energy hub operator is a function of the investment cost, incentives received from the government, and the annual cash flow from selling the renewable product. In the NPV formula, annual revenue is the revenue from selling renewable products to the energy consumer, and the annual cost is the operation and maintenance cost of the technologies as well as taxes paid to the government. A project lifetime of 20 years (T) and a discount rate (r) of 8% is considered for all scenarios.

Energy consumer: The energy consumer emits GHG emissions by natural gas consumption for industrial heating and diesel consumption for diesel forklifts. Energy consumer contributes to the economic development by paying profit taxes to the government. The objective of the energy consumer is to minimize the additional cost imposed by buying more expensive renewable energies. Equation 4-4 shows the energy hub operator's objective function.

$$Energy\ consumer's objective = Min(additional\ cost) \quad 4\text{-}4$$

The additional cost is the sum of the cost paid for forklifts purchase, charging/refueling infrastructure, and purchasing hydrogen. The cost the energy consumer pays for the energy infrastructure development is named "additional cost" since it is additional to what the energy consumer is spending in its status quo. The additional cost can also be in the form of global adjustment. Electricity consumers in Ontario are charged the hourly Ontario electricity price (HOEP) for the energy they consume as well as a Global Adjustment (GA) cost. GA is charged for investing in new generation capacity, maintaining current capacity, and developing conservation and energy management plans [7]. The GA considered in this study is the difference between the HOEP (which is the market clearance price) and feed-in tariff (FIT) price the energy consumers pay for the development of a new electricity generation capacity. Equation 4-5 shows that the GA at each hour is the FIT price paid by the consumer minus the HOEP. The assumption in this study is that the GA is distributed evenly among the consumers. This assumption is not necessarily correct for all electricity consumers in Ontario.

$$GA(t) = FIT(t) - HOEP(t) \quad \text{4-5}$$

4.2.4 Scenarios

In this study, we are comparing two streams of government support policy for renewable and clean technologies development:

1. Incentivizing renewable energy generation technologies for increasing the share of renewable energies in the electricity system; and
2. Incentivizing technologies and systems which use clean electricity to replace fossil fuels in other sectors of an energy system such as the transportation, residential and industrial sectors.

For each of these streams of government support, we analyze different scenarios as explained in the following.

4.2.4.1 Scenario 1: Wind power

In this scenario, we assume that the government is supporting the development of wind power systems to increase the share of renewable energies in the electricity grid. In case 1, we assume that the wind power is replacing natural gas plants (which generates power on top of nuclear and hydropower plants) while in case 2, the wind farm is replacing current Ontario's electricity mix. The energy hub operators receive a FIT for every kWh of electricity they produce. A 10 MW wind farm consisting of 10 1-MW wind turbines is considered in this scenario. The cut-in wind speed, rated wind speed and cut-off wind speed of the turbine are assumed to be 3 meters per second, 13 meters per second, and 25 meters per second, respectively. It is also assumed that the power curve of the turbine is shown in Figure 4-5.

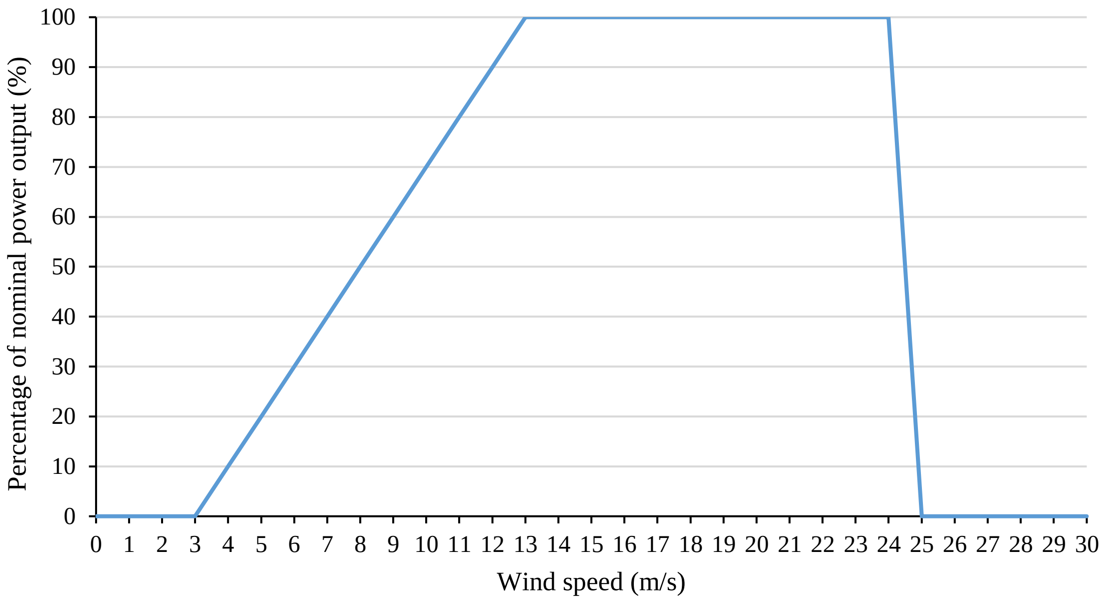


Figure 4-5. Wind turbine power curve

A typical wind speed profile was used to calculate the output wind power. The wind farm power factor was calculated to be around 30% using that wind profile.

4.2.4.2 Scenario 2: Solar power

In this scenario, we are assuming the government is supporting the development of solar power capacity to increase the share of renewable energies in the electricity grid. In case 1, we are assuming that solar power is replacing natural gas plants (which generates power on top of nuclear and hydropower plants). A 9.9 MW wind farm consisting of 55,000 180-Watts solar panels are considered in this scenario. The cell efficiency and module efficiency are considered to be 17% and 14%, respectively. The solar system doesn't have a solar tracker system. The energy hub operators receive a FIT for every kWh of electricity they produce. In this scenario, the investment cost and operation and maintenance cost of the energy hub operator is limited to the solar PV panels. In case 2, it is assumed that the solar farm is replacing current Ontario's electricity mix.

4.2.4.3 Scenario 3: Power-to-Gas

In this scenario, we assume that the energy hub operator is investing in hydrogen infrastructure (both generation and refueling) and sells the hydrogen to the energy consumer. The energy consumer buys the hydrogen for use as HENG and also for refueling fuel cell-powered forklifts. Figure 4-6 shows the energy block diagram in scenario 3: Power-to-Gas.

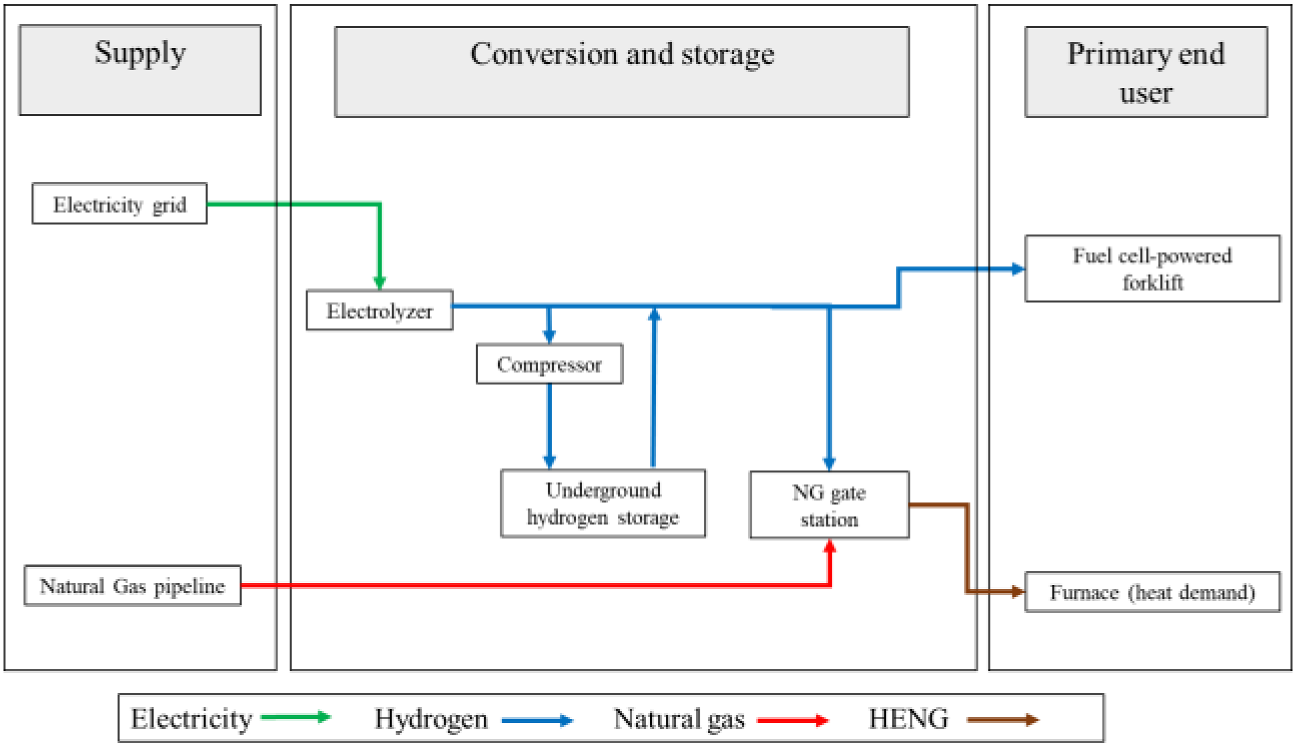
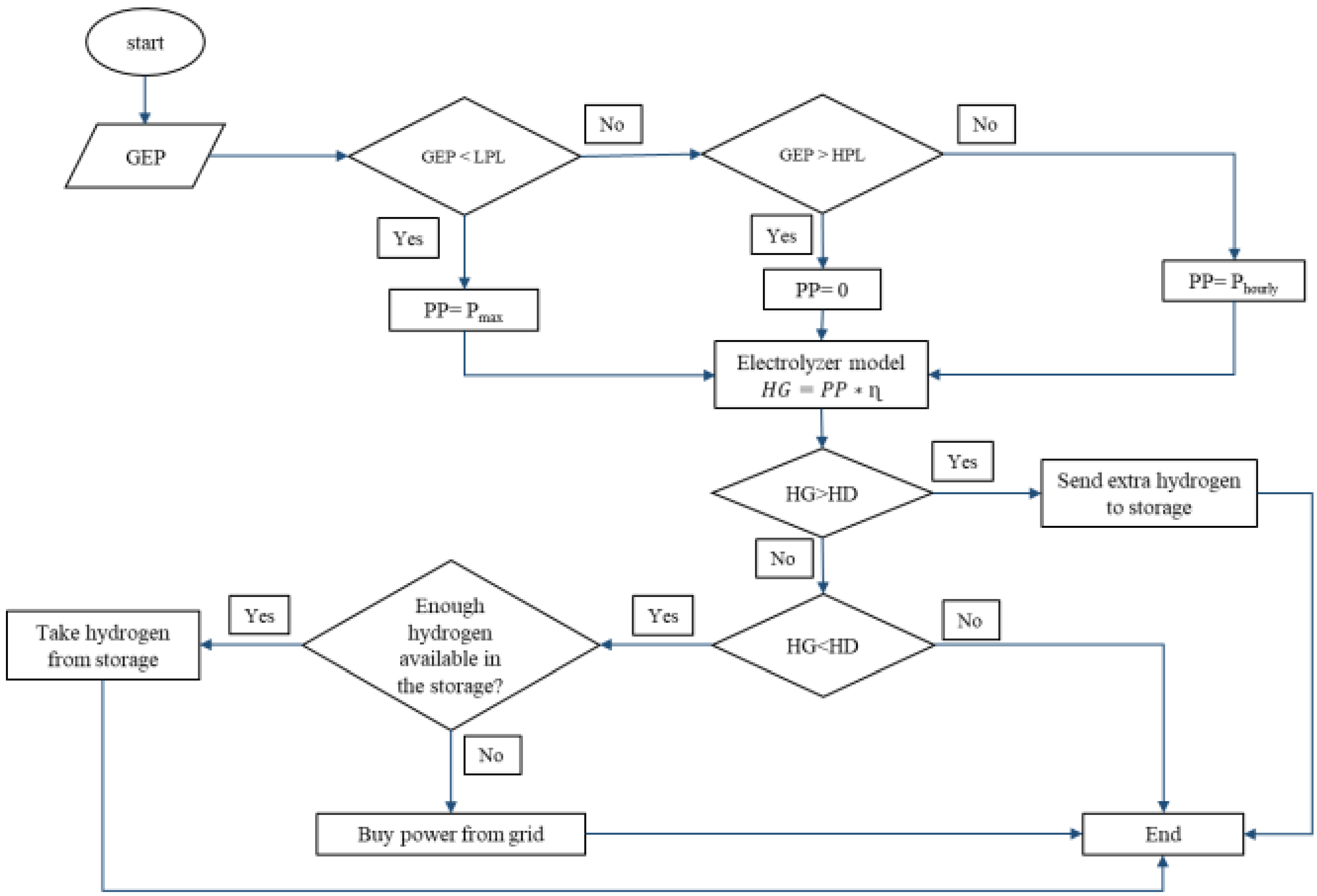


Figure 4-6. The energy block diagram in Scenario 3: Power-to-Gas

The energy hub operator charges a certain price for each m^3 of hydrogen they sell to the consumers. This price is determined based on the costs of the energy hub, the incentives paid by the government and a guaranteed 7-year payback period. The natural gas is consumed on-site in a furnace with a consumption rate of 1500 m^3 per hr. For a 5% hydrogen injection to the natural gas, 78 m^3 of hydrogen is needed each hour. The energy consumer has ten forklifts and wants to replace them with fuel cell-powered forklifts. To do that, 108.26 m^3 of hydrogen is needed every eight hours. The energy hub operator stores hydrogen when the electricity prices are lower than a certain limit and uses the stored hydrogen to meet the demand when the electricity prices are higher than a certain value.

Figure 4-7 shows the underground hydrogen storage operation flowchart for Scenario 3, Power-to-Gas.



GEP: Grid Electricity Price, LPL: Lower Price Limit, HPL: Higher Price Limit, HG: Hydrogen Generated, HD: Hydrogen Demand, η: Electrolyzer Efficiency, PP: Purchased Power, P_{max} :maximum electrolyzer power input, P_{hourly} :power needed to meet the hydrogen demand in an hour

Figure 4-7. Underground hydrogen storage operation flowchart for Scenario 3, Power-to-Gas

In this scenario, we are considering two cases of government support for the development of Power-to-Gas infrastructure. In the first case, the government pays no capital grant incentive to the energy hub operator. However, the government will pay for the fuel cell-powered forklifts purchased by the energy consumer. In the second case, the government pays a capital grant to the energy hub operator and pays no incentive to the energy consumer.

4.2.4.4 Scenario 4: Battery-powered forklifts

In this scenario, we consider using electricity to charge battery-powered forklifts to replace diesel forklifts. Between 11 pm and 7 am the energy hub operator charges three batteries for each forklift which will be used in the next three shifts by the consumer. The consumer pays the energy hub operator for charging the batteries they use. The energy block diagram for this scenario is shown in Figure 4-8.

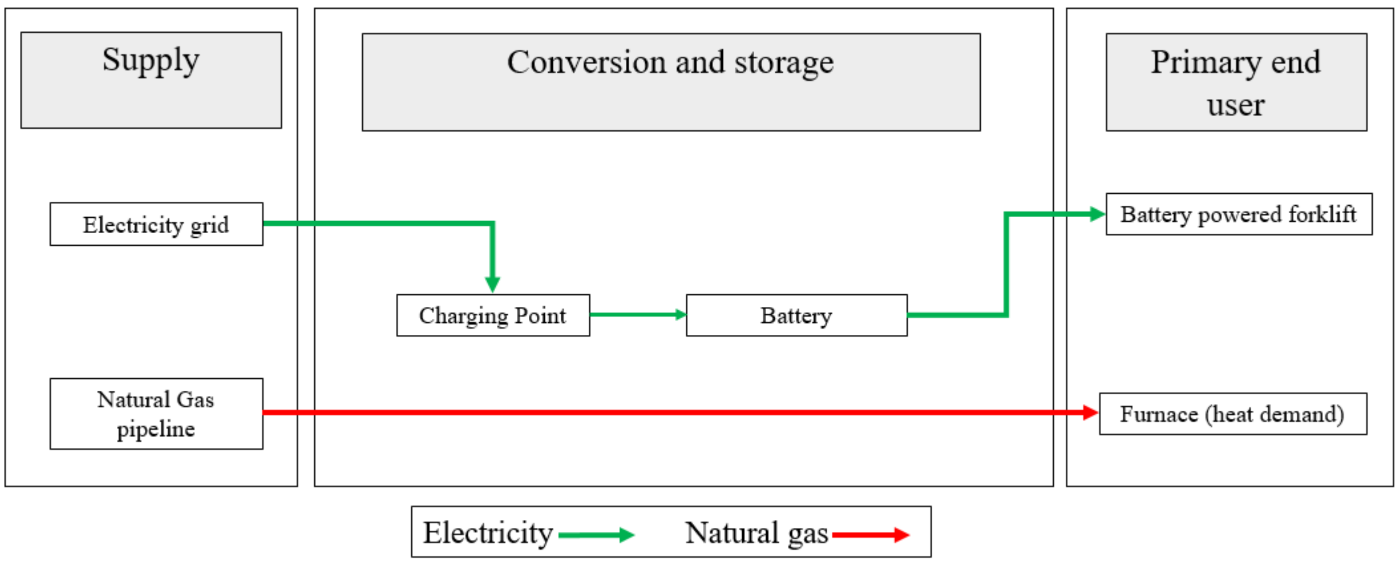


Figure 4-8. Energy block diagram for Scenario 4: Battery-powered forklifts

Two cases of government incentives for the energy hub operator and incentive for the energy consumer are considered in this scenario.

For each of these scenarios, we aim to investigate:

1. How much is the reduced health impacts?
2. How much GHG emission reduction is achieved?
3. How profitable is the investment for the energy hub operator?
4. How high is the extra cost to the energy consumer?

In this study, two types of GHG emission reduction are analyzed. The first type is GHG emission reduced at the energy consumer's site. The second type is the lifecycle GHG emission. Figure 4-9 shows the difference between the on-site and lifecycle emissions considered in this study.

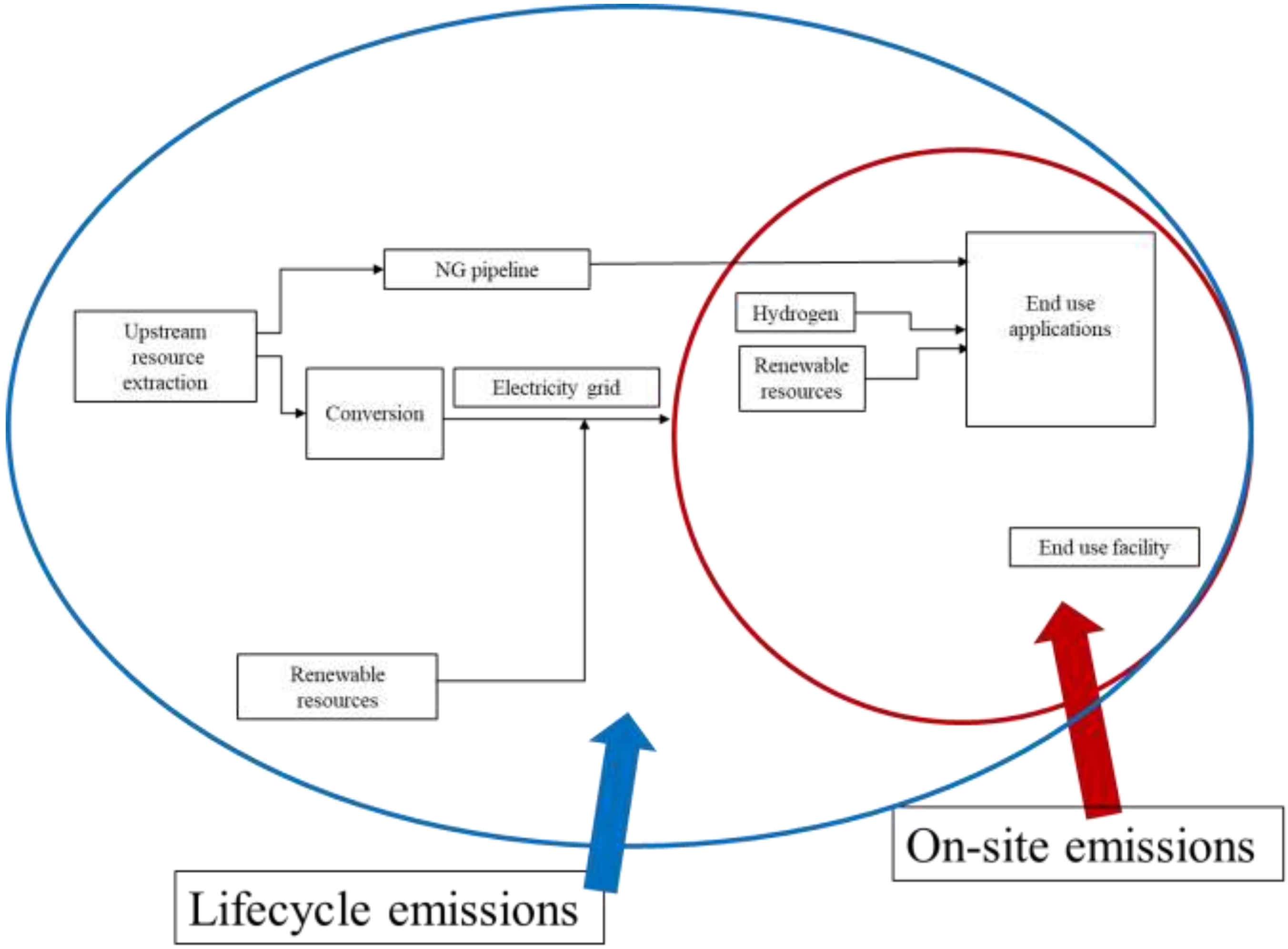


Figure 4-9. On-site and lifecycle emissions

As can be seen in Figure 4-9, on-site and lifecycle emissions are different in each scenario.

4.2.5 Input data

The cost of technologies considered in this study is shown in Table 4-5. All values are converted to 2017 CAD.

Table 4-5. Assumed cost of energy conversion and storage technologies

Technology	Capital cost (2017 CAD)	Annual O&M cost
Alkaline Electrolyzer (CAD per kW)	1076 [70]	Assumed to be 4% of the capital cost
Wind turbine (CAD per kW)	1475 [110]	95 CAD per kW [110]
Solar panel (CAD per Wac)	1.74 [111]	24 CAD per kW [111]
Electrolyzer stack replacement	30% of electrolyzer capital cost	Already included in the electrolyzer operation and maintenance cost
Battery (CAD per kWh)	723 [112]	Assumed to be 1% of the capital cost
Underground storage preparation cost (CAD per m^3 Hydrogen)	0.38 [70]	0

The costs of fuel cell-powered, battery-powered, and diesel forklift are shown in Table 4-6. All values are converted to 2017 CAD.

Table 4-6. Assumed associated costs of fuel cell-powered, battery-powered and diesel forklift

Cost	Fuel cell-powered forklift	Battery-powered forklift	Diesel forklift
Purchase cost per forklift (CAD)	48,000 [113]	34,500 [113]	NA
Refueling/charging infrastructure capital cost	6780 CAD per kg per day hydrogen refueling capacity [114]	1200 CAD per charger	NA
Annual O&M cost of refueling/charging infrastructure	4% of capital cost	4% of capital cost	NA
Routine Maintenance Costs per forklift (CAD per year per forklift)	1090 [113]	5450 [113]	350 [113]

Fuel cell/ battery maintenance cost (CAD per year per forklift)	2920 [98]	6360 [98] (Considering 4 batteries for each forklift)	NA
Labor cost of refueling/recharging (CAD per year per forklift)	1060 [98]	5830 [98]	1060 (Assumed to be equal to the cost of hydrogen refueling)

For every 24 kWh of electricity (from the wall to power) used in battery-powered forklifts (equivalent to 15 kWh to the wheels), 1 kg of hydrogen is needed to power a fuel cell-powered forklift [115]. It is also assumed that for every kWh of electricity delivered to a battery-powered forklift, 0.16 gallons of diesel is needed to fuel a diesel forklift [115]. In this study, we assume that the battery-powered forklift consumes 2.85 kW of power per hour and the battery is charged at the same rate [113]. Diesel price is assumed to be 1.075 CAD per liter [116].

The electricity used to charge electric forklifts and produce hydrogen is bought from the electricity grid. The generation of grid electricity is associated with emissions. Emissions from operation and maintenance of electricity generation technologies considered in Ontario are shown in Table 4-7.

Table 4-7. Assumed GHG emission rates of electricity generation technologies [72]

Technology	**GHG emission (g CO_{2e} per kWh)**
Hydroelectric	0
Nuclear	0.15
Wind	0.74
Solar	6.15
Natural gas	525

It should be noted that hydropower emissions are not zero for new plants, but it is assumed to be zero in Ontario with legacy hydropower generation.

Natural gas price is assumed to be 19 cents per m^3 based on the values available in [117]. It should be noted that we used HOEP as the electricity purchase cost. This was done to assess how cost-effective it is to use surplus electricity in Ontario to reduce GHG emissions in other sectors of energy when the surplus power is sold to the businesses at the HOEP. In Scenario 4: Battery-powered forklifts, batteries are only charged during off-peak hours in Ontario. Off-peak hours as shown in Table 4-8, usually have a 10% lower demand compared to mid-peak and on-peak hours.

Table 4-8. Average electricity demand in off-peak, mid-peak, and on-peak hours in Ontario (data gathered from [118])

Month	**Off-peak hours average demand (MWh)**	**Mid-peak hour average demand (MWh)**	**On-peak hours average demand (MWh)**	**Off-peak to mid-peak demand ratio**	**Off-peak to on-peak demand ratio**
January	15816	17253	17366	0.92	0.91
February	15251	16509	16914	0.92	0.90
March	15210	16095	16682	0.95	0.91
April	13084	14602	14937	0.90	0.88
May	12990	14825	14740	0.878	0.88
June	14064	15838	16210	0.89	0.87
July	14286	15988	16783	0.89	0.85
August	14317	16633	17593	0.86	0.81
September	13713	16834	17416	0.81	0.79
October	13543	14496	14198	0.93	0.953
November	14688	16050	16494	0.92	0.89
December	16051	17431	17623	0.92	0.91

Table 4-9 shows the on-peak, mid-peak, and off-peak hours in winter and summer in Ontario.

Table 4-9. On-peak, mid-peak, and off-peak hours in Ontario [119]

	On-peak hours	**Mid-peak hours**	**Off-peak hours**
Summer	11 AM- 5 PM	5 PM- 7 PM and 7 AM- 11 AM	7 PM- 7 AM
Winter	5 PM- 7 PM and 7 AM- 11 AM	11 AM- 5 PM	7 PM- 7 AM

Emission rates of pollutants from a combined cycle power plant, natural gas consumption, and diesel consumption are presented in Table 4-10, Table 4-11, and Table 4-12.

Table 4-10. Assumed emission rates of pollutants from a combined cycle power plant [108]

Pollutant	**Emission rate (kg per MWh)**
CO	0.24
NO_2	0.16
$PM_{2.5}$	0.15
SO_2	0.021

Table 4-11**.** Assumed emission rates for natural gas combustion [120]

Pollutant	**Emission rate (lb per 10^6 scf)**
CO	84
NO_2	100
$PM_{2.5}$	7.6
SO_2	0.6
CO_2	120,000
CH_4	2.3
N_2O (Controlled-low-NO_X burner)	0.64

Table 4-12. Assumed emission rates for diesel combustion [121], [122]

Pollutant	**Emission rate**
CO (lb per MMBtu) [121]	0.95
NO_2 (lb per MMBtu) [121]	4.41
$PM_{2.5}$ (lb per MMBtu) [121]	0.31
SO_2 (lb per MMBtu) [121]	0.29
CO_2 (kg per gallon) [122]	10.18
CH_4 (g per gallon) [122]	0.42
N_2O (Controlled-low-NO_X burner) (g per gallon) [122]	0.08

To calculate the CO_{2e} for fossil fuel combustion, coefficients of 25 and 298 were used for CH_4 and N_2O, respectively [123].

4.3 Results and discussion

In this section, the results for each scenario and case are presented and compared to each other.

4.3.1 Scenario 1: Wind power

4.3.1.1 Scenario 1, Case 1: Wind power replacing natural gas power plants

In this scenario, the government pays one million CAD in capital grant incentives to the energy hub operator and guarantees a 7-year payback period via a fixed feed-in tariff (FIT) for the wind power they generate. The energy consumer in this scenario is assumed to be the industrial sector in Ontario. In 2015, 137 TWh of electricity was consumed in Ontario [124] of which 41.7 TWh was consumed in the industrial sector [125]. As a result, about 30% of the electricity consumption in Ontario was consumed in the industrial sector. We are using this percentage for calculating the cost of the global adjustment for energy consumers in the province. Table 4-13 shows the economic parameters of the energy hub operator in Scenario 1.

Table 4-13. Economic parameters of the energy hub operator in Scenario 1, Case 1: wind power replacing natural gas plants

Parameter	Value
Investment	14.75 million CAD
Capital grant received from the government	1 million CAD
FIT value	12.7 Cents per kWh
Payback period	7 years
NPV	11.2 million CAD

Table 4-14 shows the economic parameters for the government in Scenario 1, Case 1: wind power replacing natural gas plants for the government. As can be seen in Table 4-14, the emission reduction cost, in this case, is a negative value for the government which means that the health impacts avoided and the taxes the government receives surpass the incentives it paid to the energy consumer.

Table 4-14. Economic parameters of the government in Scenario 1, Case 1: wind power replacing natural gas plants

Parameter	Value
Capital grant paid	1 million CAD
Health impacts avoided	115,515 CAD
Taxes collected from the energy hub operator	113,870 CAD
Taxes lost for electricity price increase in the industrial sector	82,891 CAD
Total CO_{2e} emissions saved	13872 tonne CO_{2e}
Emission reduction cost	-3.218 CAD per tonne CO_{2e}

Figure 4-10 shows the components of the emission reduction cost for the government in Scenario 1, Case 1: wind power replacing natural gas plants. As can be seen in Figure 4-10, health impacts avoided and the taxes collected from the energy hub operator cover the incentives paid by the government and the taxes lost for electricity price increase for the energy consumer.

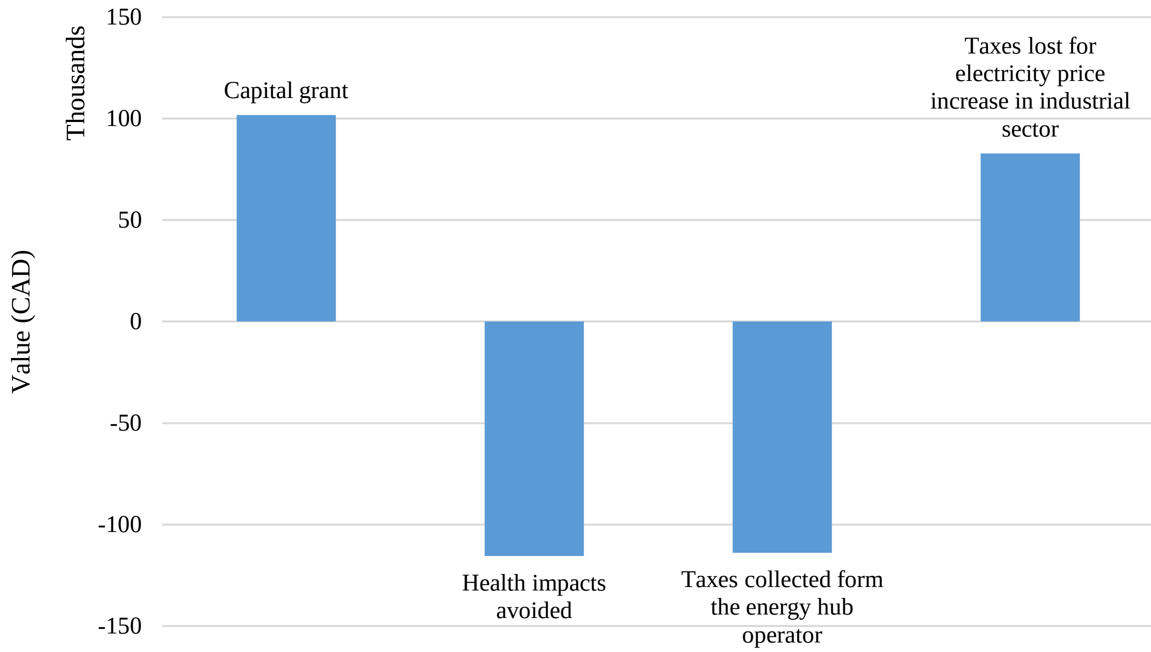


Figure 4-10. Annual costs and revenues of government in reducing GHG emissions in Scenario 1, Case 1: wind power replacing natural gas plants

The health impacts avoided in this case are high as wind power is replacing natural gas plant which is the only polluting electricity source in Ontario. Due to the high profitability of the investment for the energy hub operator, the government receives noticeable taxes from the energy hub operator.

Table 4-15 shows the economic parameters of the energy consumer in Scenario 1, Case 1: wind power replacing natural gas plants. The additional cost for the consumer is the global adjustment paid because of the FIT received by the energy hub operator. In this case, the energy consumer is paying CAD 59.76 per tonne of CO_{2e} reduction in the province.

Table 4-15. Economic parameters of the energy consumer in Scenario 1, Case 1: wind power replacing natural gas plants

Parameter	Value
Additional cost paid for the energy policy	828,914 CAD
On-site saved CO_{2e} emissions	0

On-site emission reduction cost	NA
Lifecycle emission reduction cost	59.76 CAD per tonne CO_{2e}

4.3.1.2 Scenario 1, Case 2: Wind power replacing Ontario's electricity mix

In this case, we are assuming that the wind farm is replacing Ontario's electricity mix. The economic parameters for the energy hub operator are the same as the values for scenario 1, Case 1: wind power replacing natural gas plants shown in Table 4-13. Similar to case 1, the energy hub operators receive a FIT of 12.7 Cents for every kWh of electricity they generate. Similarly, the investment cost and operation and maintenance cost of the energy hub operator is limited to the wind turbines. Table 4-16 shows the economic parameters of the government in Scenario 1, Case 2: Wind power replacing Ontario's electricity mix. As can be seen in Table 4-16, the emission reduction cost has increased drastically for the government compared to case 1.

Table 4-16. Economic parameters of the government in Scenario 1, Case 2: Wind power replacing Ontario's electricity mix

Parameter	Value
Capital grant paid	1 million CAD
Health impacts avoided	4771 CAD
Taxes collected from the energy hub operator	113,870 CAD
Taxes lost for electricity price increase in the industrial sector	82,891 CAD
Total CO_{2e} emissions saved	560.31 tonne CO_{2e}
Emission reduction cost	117.98 CAD per tonne CO_{2e}

Figure 4-11 better reflects the reason behind this increase. Figure 4-11 shows the annual costs and revenues of the government in reducing GHG emissions in Scenario 1, Case 2: Wind power replacing Ontario's. As can be seen in Figure 4-11, in this case only the taxes collected from the energy hub operator reduce the costs for the government and the avoided health impacts are negligible compared to the grants paid and lost taxes. The reason for reduced health impacts is the 95% emission-free electricity mix in Ontario. This leads to low health impacts avoided when the grid power is replaced with wind power.

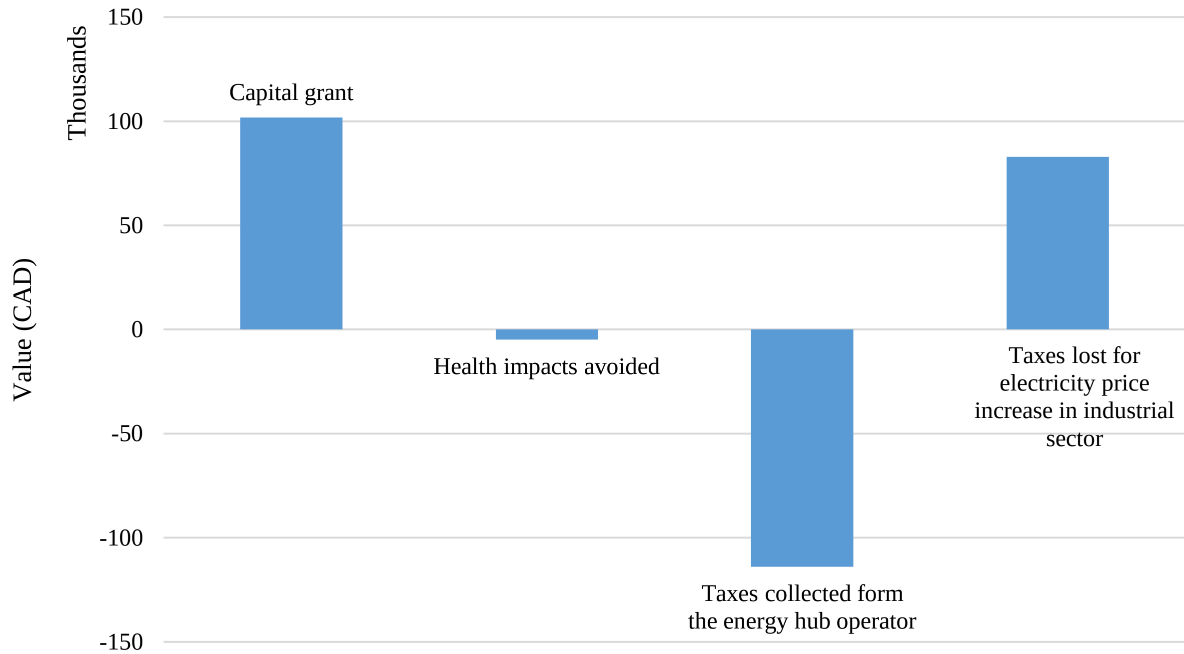


Figure 4-11. Annual costs and revenues of government in reducing GHG emissions in Scenario 1, Case 2: Wind power replacing Ontario's electricity mix

The lifecycle emission reduction cost for the energy consumer is 1479.39 CAD per tonne of CO_{2e}. Comparing Scenario 1, Case 1: Wind power replacing natural gas plants and Scenario 1, Case 2: Wind power replacing Ontario's electricity mix shows that when the grid electricity mix moves from 100% natural gas to current Ontario electricity grid mix (Figure 4-3) the cost of GHG emission reduction by replacing the current technology mix with wind power increases more than 24 times for the energy consumer.

4.3.2 Scenario 2: Solar power

4.3.2.1 Scenario 2, Case 1: Solar power replacing natural gas power plants

Similar to Scenario 1: Wind power, in this scenario the government pays 1 million CAD in the capital grant to the energy hub operator and guarantees a fixed FIT. The energy consumer pays the GA for the new renewable generation capacity.

Table 4-17 shows the economic parameters of the energy hub operator in Scenario 2, Case 1: Solar power replacing natural gas power plants.

Table 4-17. Economic parameters of the energy hub operator in Scenario 2, Case 1: Solar power replacing natural gas power plants

Parameter	**Value**
Investment	13.27 million CAD
Capital grant received from the government	1 million CAD
FIT value	18.45 Cents per kWh
Payback period	7 years
NPV	9.87 million CAD

Table 4-18 shows the economic parameters of the government in Scenario 2, Case 1: Solar power replacing natural gas power plants. As can be seen in Table 4-18, the emission reduction cost for the government is lower than one CAD per tonne of CO_{2e}.

Table 4-18. Economic parameters of the government in Scenario 2, Case 1: Solar power replacing natural gas power plants

Parameter	**Value**
Capital grant paid	1 million CAD
Health impacts avoided	68,293 CAD
Taxes collected from the energy hub operator	100,480 CAD
Taxes lost for electricity price increase in the industrial sector	74,819 CAD

Total CO_{2e} emissions saved	8,116 tonne CO_{2e}
Emission reduction cost	0.97 CAD per tonne CO_{2e}

Figure 4-12 shows the annual costs and revenues of the government in reducing GHG emissions in Scenario 2, Case 1: Solar power replacing natural gas power. As can be seen in Figure 4-12, the avoided health impacts and taxes collected from the energy hub operator almost fully cover the capital grant and the lost taxes for the government.

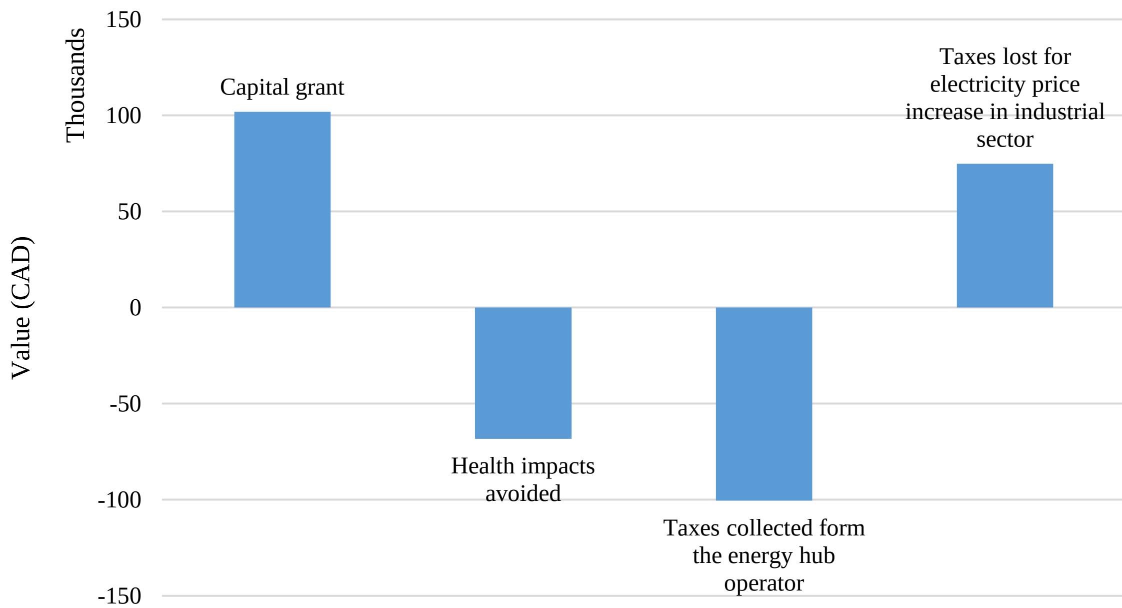


Figure 4-12. Annual costs and revenues of government in reducing GHG emissions in Scenario 2, Case 1: Solar power replacing natural gas power

Table 4-19 shows the Economic parameters of the energy consumer in Scenario 2, Case 1: Solar power replacing natural gas power. As can be seen in Table 4-19, the energy consumer is paying 92.18 CAD per tonne of CO_{2e} emission reduction.

Table 4-19. Economic parameters of the energy consumer in Scenario 2, Case 1: Solar power replacing natural gas power

Parameter	**Value**
Extra cost paid for the energy policy	748,190 CAD
On-site saved CO_{2e} emissions	0

On-site emission reduction cost	NA
Lifecycle emission reduction cost	92.18 CAD per tonne CO_{2e}

Comparing the results in Scenario 2, Case 1 (Solar power replacing natural gas power plants) and Scenario 1, Case 1: Wind power replacing natural gas power plants) shows that reducing emissions from the electricity grid is more cost-effective with wind power technology compared to solar power technology in Ontario. The two reasons for this advantage are lower investment cost for wind power technology and higher capacity factor of wind power (about 30%) compared to solar power (about 16%).

4.3.2.2 Scenario 2, Case 2: Solar power replacing Ontario's electricity mix

In this case, we are assuming that the solar farm is replacing Ontario's electricity grid mix. The economic parameters for the energy hub operator are the same as those in Scenario 2, Case 1: Solar power replacing natural gas power as shown in Table 4-17.

Table 4-20 shows the economic parameters of the government in Scenario 2, Case 1: Solar power replacing Ontario's electricity mix.

Table 4-20. Economic parameters of the government in Scenario 2, Case 2: Solar power replacing Ontario's electricity mix

Parameter	**Value**
Capital grant paid	1 million CAD
Health impacts avoided	3,335 CAD
Taxes collected from the energy hub operator	100,479 CAD
Taxes lost for electricity price increase in the industrial sector	74,819 CAD
Total CO_{2e} emissions saved	309.37 tonne CO_{2e}
Emission reduction cost	239.94 CAD per tonne CO_{2e}

As can be seen in Table 4-20, the cost of emission reduction for the government, in this case, has increased from 0.97 to 239.94 CAD per tonne CO_{2e} compared to Scenario 2, Case 1: Solar power replacing natural gas power plants. The reason for this increase can be seen in Figure 4-13. Figure 4-13 shows the annual costs and revenues of the government in reducing GHG emissions in Scenario 2, Case 1 (Solar power replacing Ontario's electricity mix). As shown in Figure 4-13, health impacts have a negligible effect on the cost of emission reduction for the government. In Scenario 2, Case 1: Solar power replacing natural gas power plants, however, the avoided health impacts have a noticeable effect and cover part of the government's incentives and lost taxes.

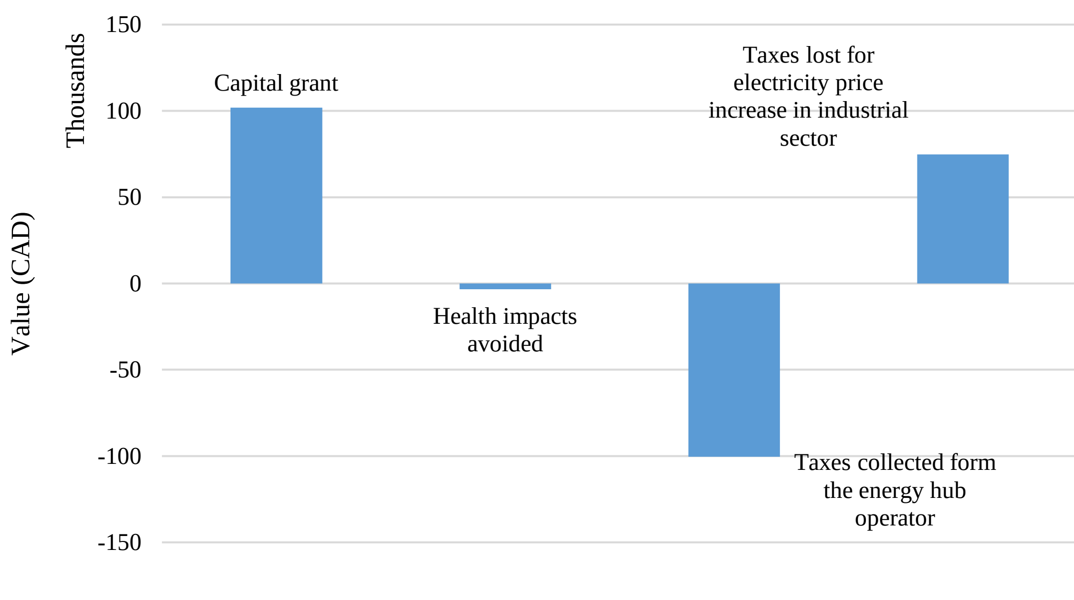


Figure 4-13**.** Annual costs and revenues of government in reducing GHG emissions in Scenario 2, Case 2: Solar power replacing Ontario's electricity mix

Lifecycle emission reduction cost for the energy consumer is 2418 CAD per tonne CO_{2e} in this case. Similar to what was observed in Scenario 1: Wind power, the cost of GHG emission reduction increases significantly for the consumer (an increase of more than 26 times) when solar power replaces the current Ontario's electricity mix instead of natural gas plants.

4.3.3 Scenario 3: Power-to-Gas

In this scenario, the development of Power-to-Gas system is investigated.

4.3.3.1 Scenario 3, Case 1: Power-to-Gas with government incentive for the energy

consumer

In the first case, the government pays no capital grant incentive to the energy hub operator. However, the government will pay for the fuel cell-powered forklifts purchased by the energy consumer. Table 4-21 shows the economic parameters for the energy hub operator. As can be seen in Table 4-21, the energy hub operator receives no capital grant from the government, but its hydrogen selling price of 5.55 CAD per kg of hydrogen is guaranteed. This price is calculated based on a 7-year payback period for the energy hub operator. The capital cost for the energy hub operator consists of the electrolyzer and hydrogen refueling infrastructure cost.

Table 4-21. Economic parameters of the energy hub operator in Scenario 3, Case 1: Government incentive for the energy consumer

Parameter	**Value**
Investment	1.74 million CAD
Capital grant received from the government	0
Hydrogen price	5.55 CAD per kg of H_2
Payback period	7 years
NPV	1.54 million CAD

Table 4-22 shows the economic parameters of the government in Scenario 3, Case 1: Government incentive for the energy consumer. As can be seen in Table 4-22, the avoided health impacts and collected taxes are large enough to cover the government's incentives and lost taxes. As a result, the government has a negative cost for emission reduction (makes money for each tonne of CO_{2e} emission reduction). This issue is better reflected in Figure 4-14.

Table 4-22. Economic parameters of the government in Scenario 3, Case 1: Government incentive for the energy consumer

Parameter	**Value**
Incentives paid	483,492 CAD
Health impacts avoided	118,683 CAD
Taxes collected from the energy hub operator	33,427 CAD

Taxes lost for electricity price increase in the industrial sector	29,854 CAD
Total CO_{2e} emissions saved	537.47 tonne CO_{2e}
Emission reduction cost	-122.55 CAD per tonne CO_{2e}

Figure 4-14 shows the components of the annual costs and revenues of government in reducing GHG emissions in Scenario 3, Case 1: Government incentive for the energy consumer. As can be seen in Figure 4-14, health impacts play an important role in reducing emission reduction cost for the government. The health impacts have been avoided to a great extent due to replacing diesel fuel with hydrogen in the forklifts.

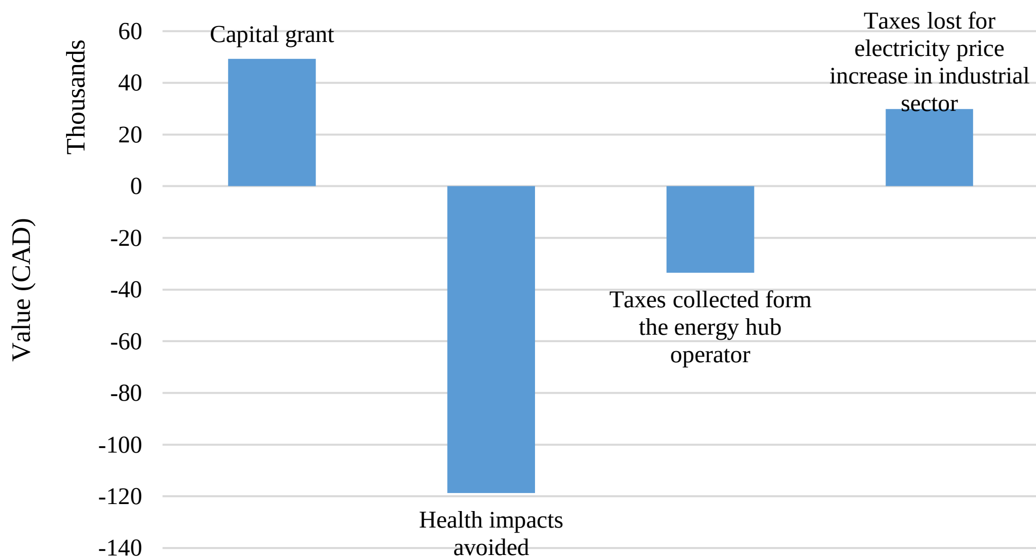


Figure 4-14. Annual costs and revenues of government in reducing GHG emissions in Scenario 3, Case 1: Government incentive for the energy consumer

Figure 4-15 shows that emission reduction from replacing diesel fuels in forklifts is about 60% of the emission reduction for replacing natural gas with HENG. However, the hydrogen consumption for forklifts is about 17% of the hydrogen consumed for HENG. The higher potential for reducing emissions by replacing diesel with hydrogen compared to replacing natural gas with HENG is due to the higher emission factors of diesel compared to natural gas. The important point to notice is that the emission reduction on-site is not equal to the lifecycle emission reduction because of the

GHG emissions from power generation that is used to produce hydrogen. If the emissions from the grid are considered, the total GHG emission reduction will drop 22%.

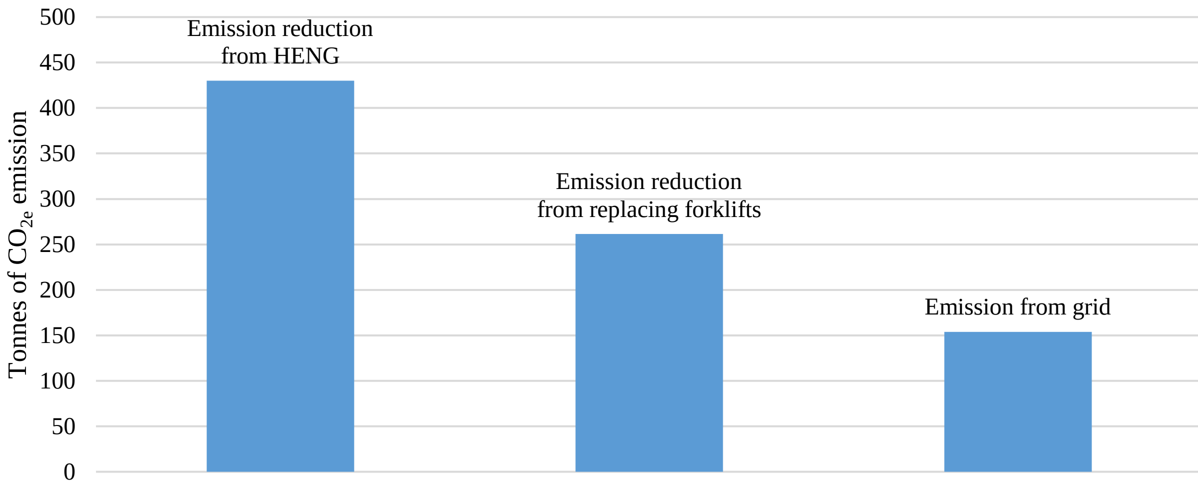


Figure 4-15. Comparing emission reduction from HENG, fuel cell-powered forklifts, and emission from the grid in Scenario 3, Power-to-Gas

Table 4-23 shows the economic parameters of the energy consumer in Scenario 3, Case 1: Government incentive for energy consumer.

Table 4-23. Economic parameters of the energy consumer in Scenario 3, Case 1: Government incentive for the energy consumer

Parameter	Value (CAD)
Extra annual cost paid for the energy policy	298,539 CAD
On-site saved CO_{2e} emissions	691.44 tonne CO_{2e}
Emission reduction cost (based on on-site emission)	431.76 CAD per tonne CO_{2e}

4.3.3.2 Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator

In this case, the government pays no incentives to the energy consumer, however, pays one million CAD to the energy hub operator in the form of a capital grant for the development of hydrogen production and storage infrastructure. Table 4-24 shows the economic parameters of the energy hub operator in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator. As can be seen in Table 4-24, the guaranteed hydrogen purchase price for the energy consumer is lower compared to Scenario 3, Case 1: Power-to-Gas with government incentive for the energy consumer. The capital cost for the energy hub operator consists of the electrolyzer and hydrogen refueling infrastructure cost.

Table 4-24. Economic parameters of the energy hub operator in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator

Parameter	**Value**
Investment	1.64 million CAD
Capital grant received from the government	1 million CAD
Hydrogen price	3.00 CAD per kg
Payback period	7 years
NPV	655,779 CAD

Table 4-25 shows the economic parameters of the government in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator. Similar to Scenario 3, Case 1: Power-to-Gas with government incentive for the energy consumer, the government, makes money for each tonne of CO_{2e} emission reduction.

Table 4-25. Economic parameters of the government in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator

Parameter	**Value**
Capital grant paid	1 million CAD
Health impacts avoided	118,683 CAD
Taxes collected from the energy hub operator	14,220 CAD
Taxes lost for electricity price increase in the industrial sector	15,571 CAD
Total CO_{2e} emissions saved	537.47 tonne CO_{2e}
Emission reduction cost	-28.80 CAD per tonne CO_{2e}

Figure 4-16 shows the annual costs and revenues of government in reducing GHG emissions in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator. Similar to the cases where wind and solar power replaced the natural gas plants, health impacts have a significant role in reducing the cost of emission reduction for the government when natural gas and diesel fuel are replaced by hydrogen.

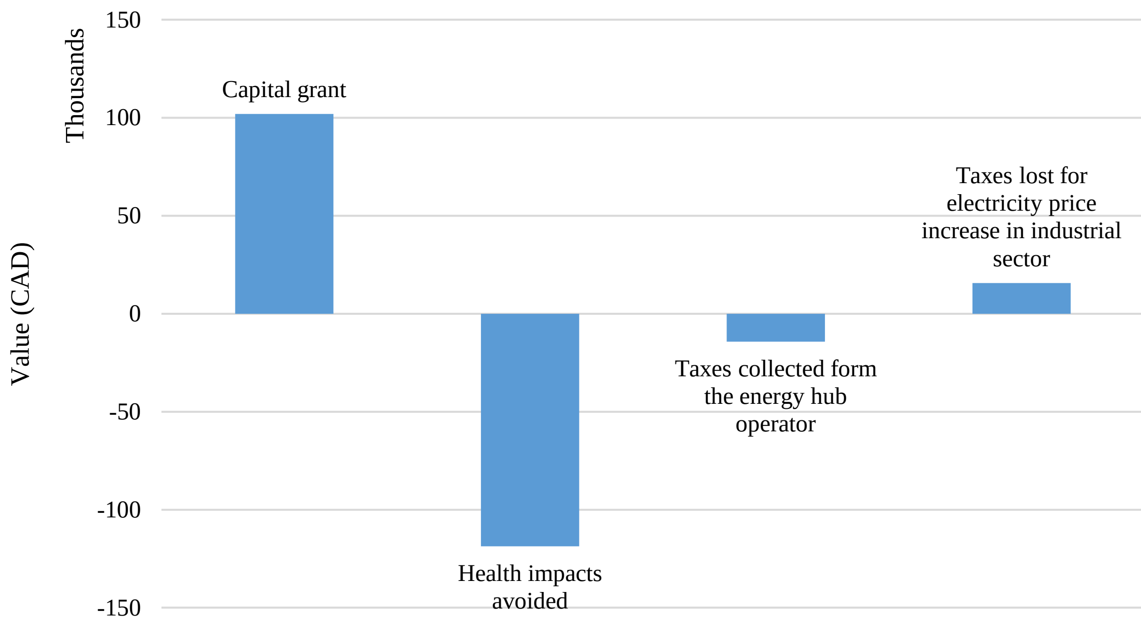


Figure 4-16. Annual costs and revenues of government in reducing GHG emissions in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator

Table 4-26 shows the economic parameters of the energy consumer in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator. The emission reduction cost, in this case, is lower for the energy consumer compared to Case 1: Power-to-Gas with government incentive for the energy consumer, although the energy hub operator doesn't receive direct incentives from the government in this case.

Table 4-26. Economic parameters of the energy consumer in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator

Parameter	Value
Extra cost paid for the energy policy	155,712 CAD
On-site saved CO_{2e} emissions	691.44 tonne CO_{2e}
Emission reduction cost (based on on-site emission)	225.20 CAD per tonne CO_{2e}

Table 4-27 compares emission reduction cost for replacing natural gas with HENG and replacing diesel forklifts with fuel cell-powered forklifts. The emission reduction per m^3 of hydrogen consumption is higher when diesel is replaced by hydrogen. The emission reduction cost in this application of hydrogen is also about half of the cost of HENG. The values in Table 4-27 are calculated based on the capital and operation and maintenance cost of the technologies only.

Table 4-27. HENG and fuel cell-powered forklift emission reduction pathways comparison in Scenario 3: Power-to-Gas

Hydrogen application	Hydrogen consumption (m^3 per year)	Emission reduction (kg of CO_{2e}) per m^3 of hydrogen consumption	Emission reduction cost (CAD per tonne of CO_{2e} emission reduction)
HENG	683,280	0.63	345.75
Fuel cell-powered forklift	118,550	2.2	160.52
Power-to-Gas average (HENG and fuel cell-powered forklift)	801,830	0.86	275.68

Figure 4-17 shows the share of annual costs for hydrogen generation for reducing emissions in Scenario 3: Power-to-Gas. Figure 4-17 shows that the electrolyzer cost (capital and O&M) with a share of 60%, has the highest share of the cost in Scenario 3: Power-to-Gas. The forklift cost purchase and maintenance) has a 27% share while the refueling infrastructure consists of 8% of the cost.

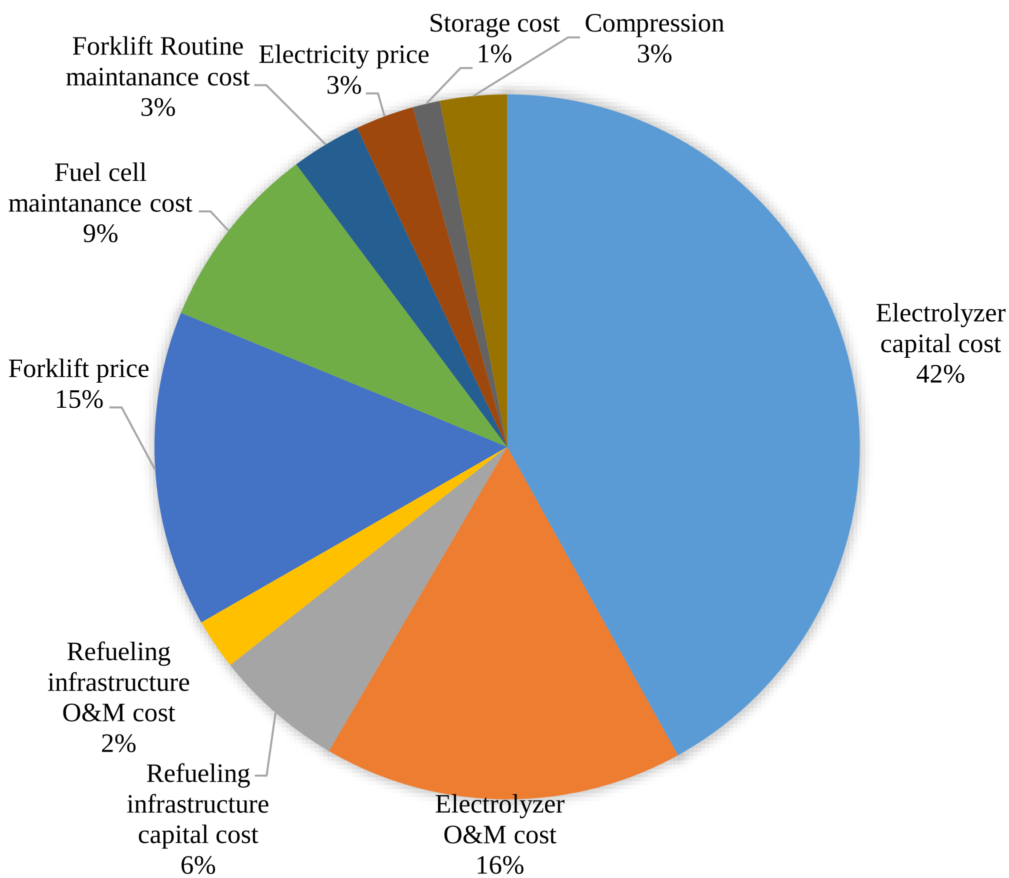


Figure 4-17. The annual cost of hydrogen generation for reducing emissions in Scenario 3: Power-to-Gas

Figure 4-18 shows the divided cost of the energy consumer in Scenario 3, Case 1: Power-to-Gas with government incentive for the energy consumer. The highest cost paid for the energy consumer is for the hydrogen and the highest cost-saving the energy consumer achieves is from the diesel cost.

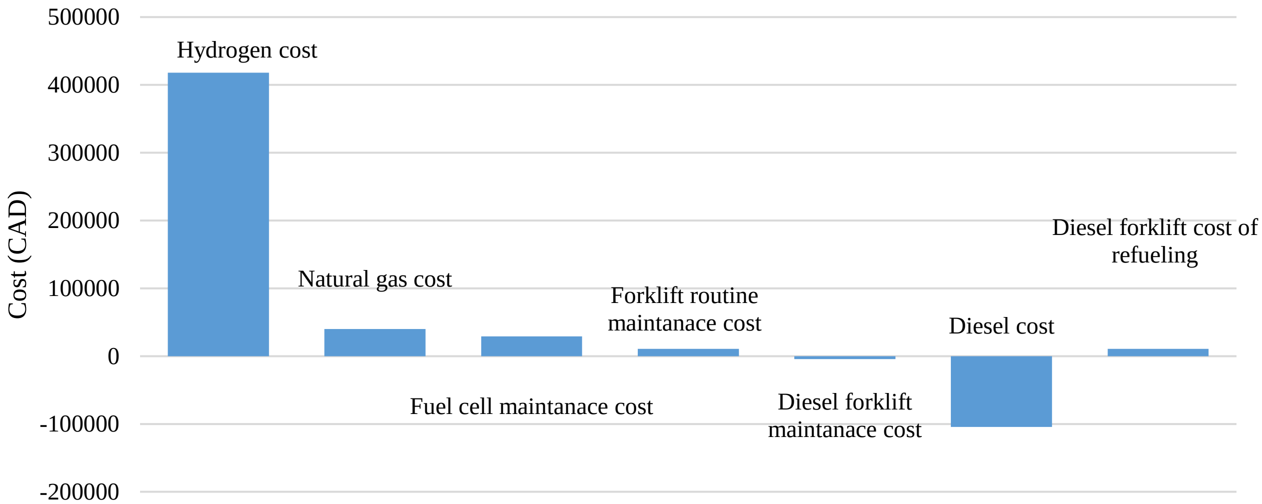


Figure 4-18. Scenario 3, Case 1: Power-to-Gas with government incentive for the energy consumer

Figure 4-19 shows the divided cost of the energy consumer in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator. Similar to Figure 4-18, Figure 4-19 shows that the highest cost paid for the energy consumer is for the hydrogen and the highest cost-saving the energy consumer achieves is from the diesel cost. However, the costs in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator is lower compared to the costs in Scenario 3, Case 1: Power-to-Gas with government incentive for the energy consumer.

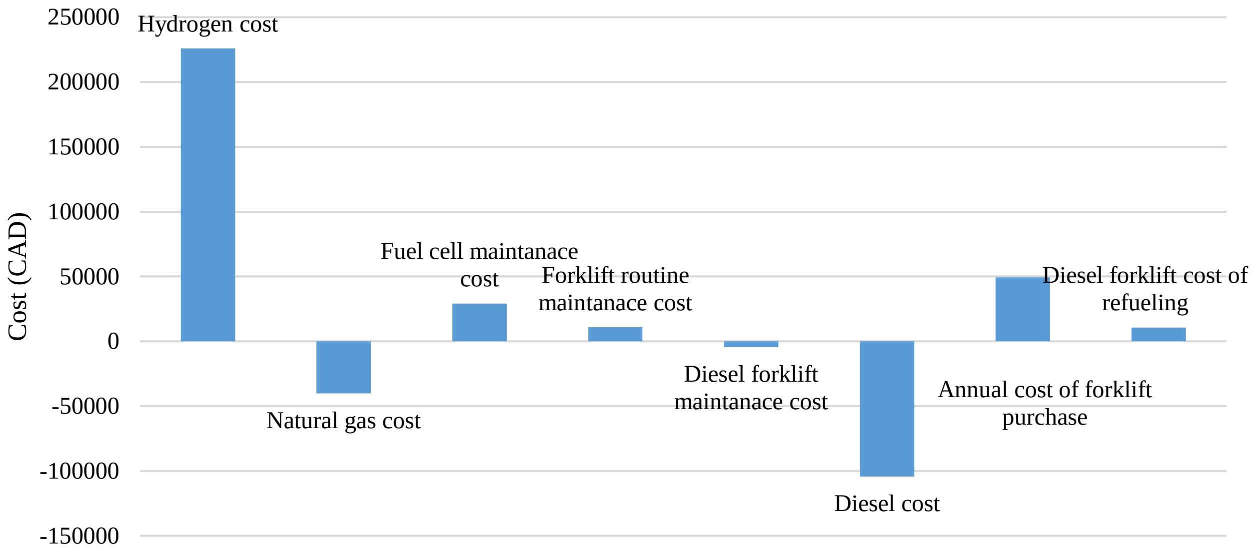


Figure 4-19. Costs paid and avoided by the energy consumer in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator

Although in Scenario 3, Case 2: Power-to-Gas with government incentive for the energy hub operator, the energy consumer is paying for the fuel cell-powered forklifts, the hydrogen cost is four times higher than the annual cost of fuel cell-powered forklifts. This means that by incentivizing hydrogen production (incentivizing the energy hub operator), the government can reduce the cost of GHG emission reduction more for the energy consumer compared to incentivizing hydrogen primary end use (such as a subsidy for forklifts). This statement can also be verified by looking at Figure 4-17. As it can be seen in Figure 4-17, about 60% of the cost of reducing GHG emissions by hydrogen is for the electrolyzer while about 35% of the cost is attributable to fuel cell-powered forklifts and refueling infrastructure investment and operation. This shows that a decrease in the cost of electrolyzer will have a significant effect on the hydrogen pathway for reducing GHG emissions.

In this analysis, electricity purchase accounted for only 3% of the cost. However, if GA is added to the electricity price, this percentage would have been higher. IESO data shows that in 2017, the average weighted Ontario electricity price was between 1 and 2 cents per kWh while GA mounted up to about 10 cents per kWh on average [7].

Comparing the results from Scenario 3: Power-to-Gas with Scenario 1: Wind power and Scenario 2: Solar power shows that the cost of GHG emission reduction for both the government and the consumer is lower when natural gas power plants are replaced by wind and solar power technologies. However, when we have a 95% emission-free electricity mix available, using clean power to reduce emissions through using hydrogen is more cost-effective in reducing GHG emissions for both the government and the energy consumer than replacing the grid mix with wind and solar power technologies.

4.3.4 Scenario 4: Battery-powered forklifts

In this scenario, the deployment of battery-powered forklifts is investigated.

4.3.4.1 Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator

In this case, the government pays 50% of the recharging infrastructure cost to the energy hub operator and pays no incentive to the energy consumer. Table 4-28 shows the economic parameters of the energy hub operator in Scenario 4, Case 1: Battery-powered forklifts with an incentive for infrastructure. The energy hub operator has a guaranteed electricity purchase price calculated based on having a 7-year payback period. It should be noted that in reality, the energy hub operator sells a "forklift charging service" to the energy consumer rather than "electricity." However, for simplicity, we are assuming that the energy consumer buys the electricity stored in batteries from the energy consumer at a certain price.

Table 4-28. Economic parameters of the energy hub operator in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator

Parameter	Value
Investment	6,000 CAD
Capital grant received from the government	6,000 CAD
Electricity selling price	35 Cents per kWh
Payback period	7 years
NPV	5,315 CAD

Table 4-29 shows the economic parameters of the government in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator. As can be seen in Table 4-29, the avoided health impacts are significantly higher than the incentives the government pays and the taxes it is losing. This significance is clearly shown in Figure 4-20, as well.

Table 4-29. Economic parameters of the government in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator

Parameter	**Value**
Capital grant paid	6,000 CAD
Health impacts avoided	112,499 CAD
Taxes collected from the energy hub operator	11,705 CAD
Taxes lost for electricity price increase in the industrial sector	45 CAD
Total CO_{2e} emissions saved	253.34 tonne CO_{2e}
Emission reduction cost	-395.64 CAD per tonne CO_{2e}

Figure 4-20 shows the annual costs and revenues of the government in reducing GHG emissions in Scenario 4, Case 1. Figure 4-20 shows that both the incentive paid by the government and taxes lost from the energy consumer is negligible in comparison with the health impacts avoided. That is the reason why the government has a negative cost of emission reduction as shown in Table 4-29.

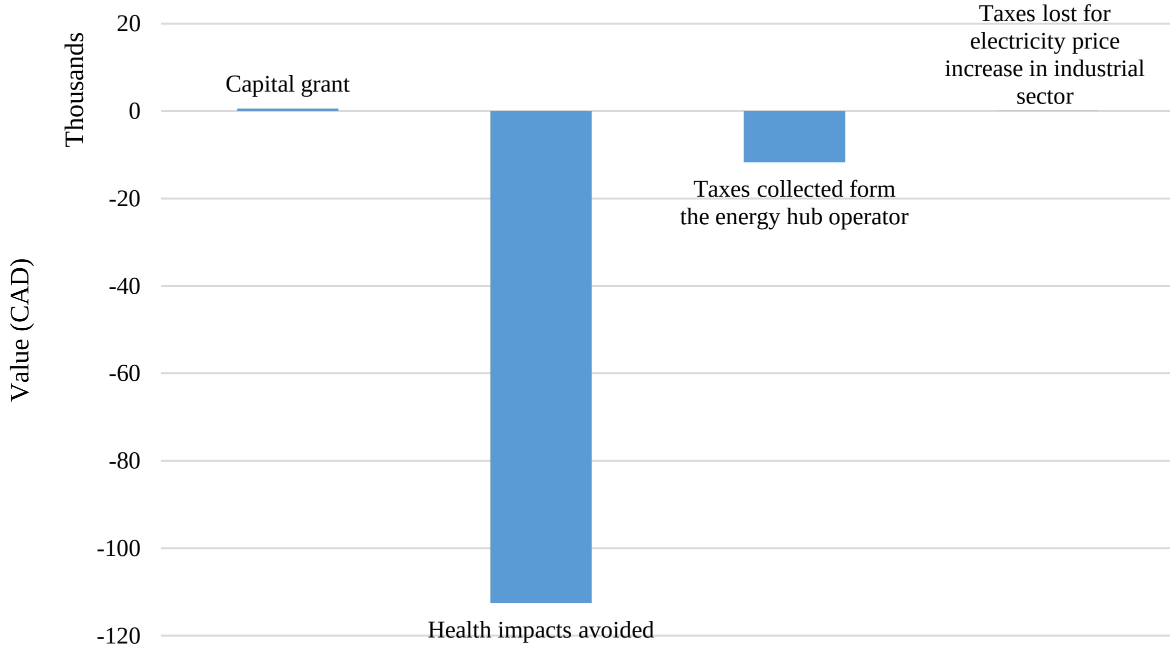


Figure 4-20. Annual costs and revenues of government in reducing GHG emissions in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator

Table 4-30 shows the economic parameters of the energy consumer in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator. The emission reduction cost for the energy consumer is 447.52 CA per tonne of CO_{2e} emission reduction which is comparable to the results in Scenario 3, Case 1: Power-to-Gas with government incentive for the energy consumer.

Table 4-30. Economic parameters of the energy consumer in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator

Parameter	**Value**
Extra cost paid for the energy policy	117,049 CAD
On-site saved CO_{2e} emissions	261.55 tonne CO_{2e}
Emission reduction cost (based on on-site emission)	447.52 CAD per tonne CO_{2e}

4.3.4.2 Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer

In this case, the government supports the replacement of diesel forklifts with battery-powered forklifts by providing an incentive equal to the price of the battery-powered forklifts to the energy consumer. Table 4-31 shows the economic parameters of the energy hub operator in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer. The capital cost for the energy hub operators consists of the battery recharging infrastructure in this case.

Table 4-31. Economic parameters of the energy hub operator in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer

Parameter	Value
Investment	12,000 CAD
Capital grant received from the government	0
Electricity selling price	36 Cents per kWh
Payback period	7 years
NPV	10630 CAD

Table 4-32 shows the economic parameters of the government in Scenario 4, Case 2. As mentioned earlier, the incentive paid by the government, in this case, is equal to the price of battery-powered forklifts. Table 4-32 shows that the emission reduction cost for the energy consumer is negative similar to Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator. Figure 4-21 reflects this issue, as well.

Table 4-32. Economic parameters of the government in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer

Parameter	Value
Capital grant paid	345,351 CAD
Health impacts avoided	124,989 CAD
Taxes collected from the energy hub operator	108 CAD

Taxes lost for electricity price increase in the industrial sector	8,303 CAD
Total CO_{2e} emissions saved	253.34 tonne CO_{2e}
Emission reduction cost	-272.87 CAD per tonne CO_{2e}

Figure 4-21 shows the annual costs and revenues of government in reducing GHG emissions in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer. Unlike Scenario 4, Case 1, i.e., Battery-powered forklifts with an incentive for the energy hub operator, where the health impacts were the dominant factors in the cost of emission reduction for the government, in Scenario 4, Case 2 the incentive paid by the government is the most significant factor. This is due to the higher cost of battery-powered forklifts compared to the recharging infrastructure.

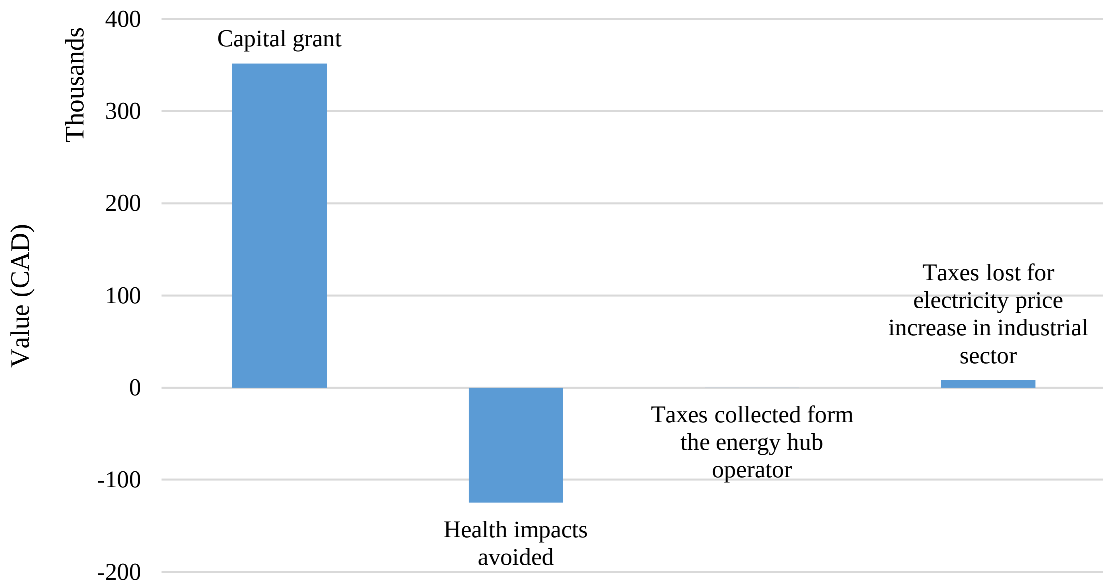


Figure 4-21. Annual costs and revenues of government in reducing GHG emissions in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer

Table 4-33 shows the economic parameters of the energy consumer in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer. The on-site emission reduction cost, in this case, is lower than the one calculated in Scenario 4, Case 1: Battery-powered forklifts with an incentive for the energy hub operator. This is contrary to the results of Scenario 3: Power-to-Gas where the emission reduction cost for the energy consumer decreased when the energy consumer was not receiving direct incentives from the government.

Table 4-33. Economic parameters of the energy consumer in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer

Parameter	**Value (CAD)**
Extra cost paid for the energy policy	83,027 CAD
On-site saved CO_{2e} emissions	261.55 tonne CO_{2e}
Emission reduction cost (based on on-site emission)	317.44 CAD per tonne CO_{2e}

Table 4-34 shows the cost of emission reduction by replacing diesel forklifts with battery-powered forklifts. Similar to Table 4-27, the values in Table 4-34 have been calculated based on investment and operation and maintenance cost of the technologies. Table 4-34 shows that the emission reduction cost with the battery-powered forklift is higher than the value for the Power-to-Gas scenario shown in Table 4-27. However, if we consider the forklift working with two batteries, the electric pathway may have equal or lower emission reduction cost compared to hydrogen technologies. In that case, the labor cost of recharging and the cost of battery maintenance will be limited to two batteries, and the cost of emission reduction will drop by about 60% (177.42 CAD per tonne CO_{2e}). This value is well below the HENG and Power-to-Gas emission reduction cost and is comparable to the fuel cell-powered forklift value reported in Table 4-27.

Table 4-34. Emission reduction cost by replacing diesel forklifts with battery-powered forklifts

Hydrogen application	**Electricity consumption (kWh per year)**	**Emission reduction (kg of CO_{2e}) per kWh of electricity consumption**	**Emission reduction cost (CAD per tonne of CO_{2e} emission reduction)**
Electric forklift	249,660	1.05	447.79

Figure 4-22 shows the annual costs of emission reduction by battery-powered forklifts in Scenario 4: Battery-powered forklifts. It can be seen in Figure 4-22 that the forklift cost (purchase, operation, and maintenance) accounts for 65% of the total cost. This high percentage shows why direct incentives for the energy consumer for purchasing forklifts lowers the cost of emission reduction for the energy consumer.

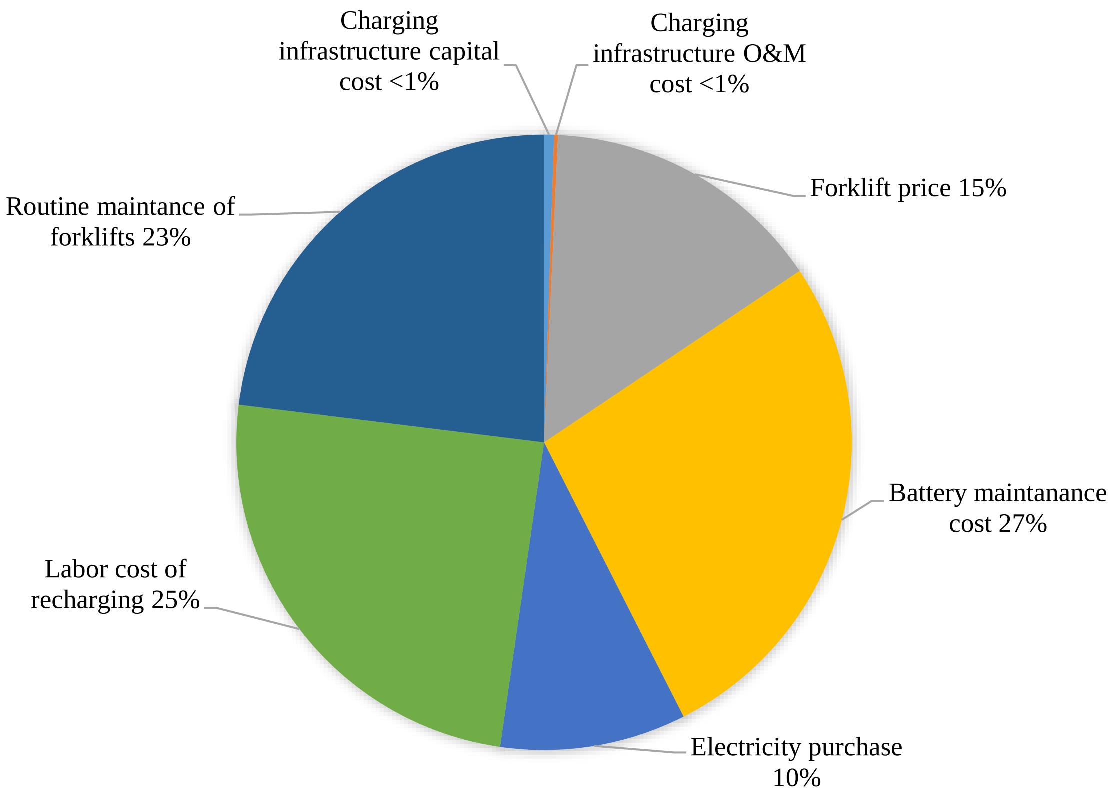


Figure 4-22. The annual costs for emission reduction by battery-powered forklifts in Scenario 4: Battery-powered forklifts

Figure 4-23 and Figure 4-24 show the costs paid and avoided by the energy consumer in Scenario 4, Case 1(Battery-powered forklifts with an incentive for infrastructure) and Case 2 (Battery-powered forklifts with an incentive for the energy consumer), respectively.

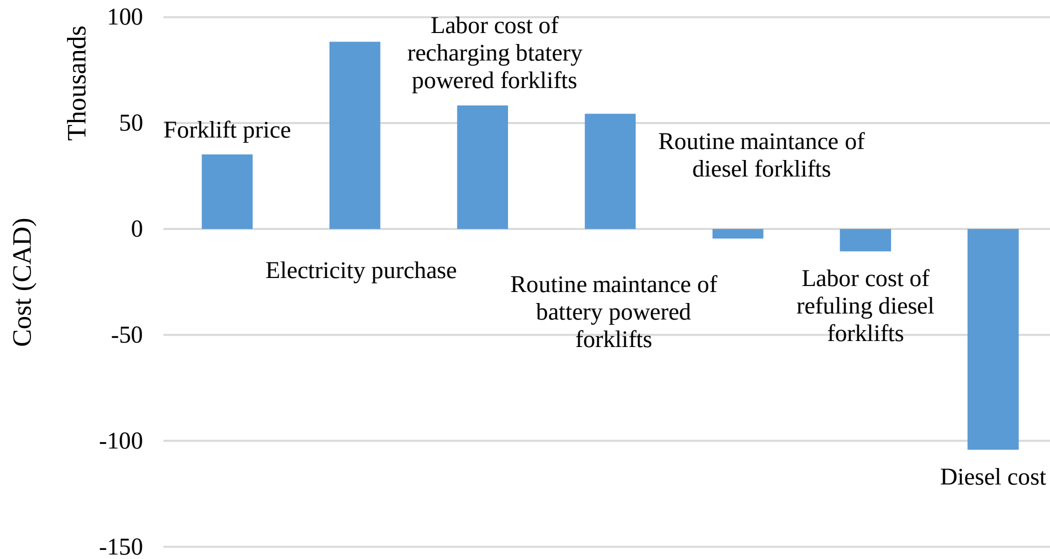


Figure 4-23. Costs paid and avoided by the energy consumer in Scenario 4, Case 1: Battery-powered forklifts with an incentive for infrastructure

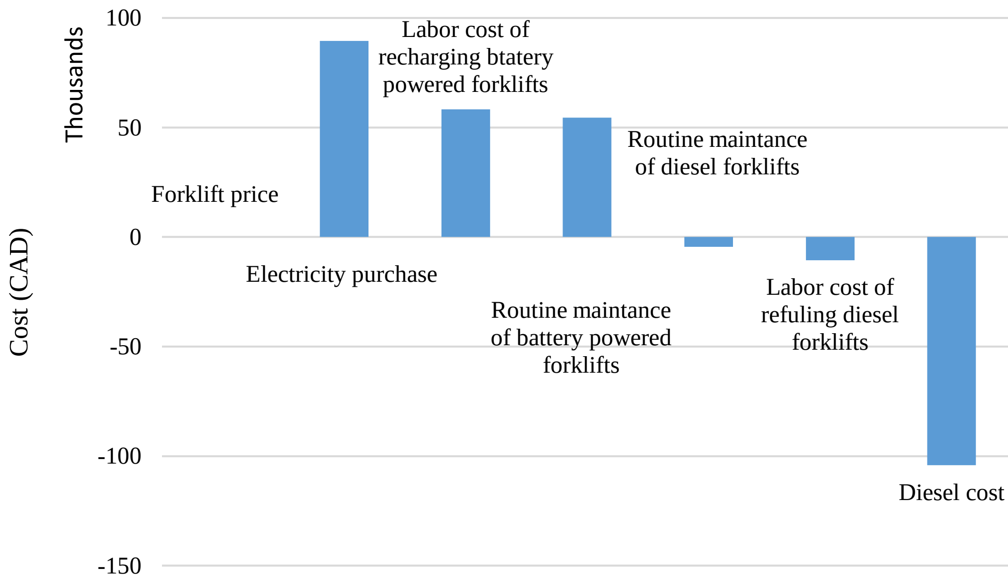


Figure 4-24. Costs paid and avoided by the energy consumer in Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer

Electricity cost is a significant factor in the total cost of the energy consumer as shown in Figure 4-23 and Figure 4-24. It should be noted that it is assumed that the consumer is not buying electricity from the energy hub operator, and is purchasing the battery-charging service from them. The battery-charging service cost is reflected in the ‘electricity purchase’ cost. GHG emission reduction in the first case is more expensive for the energy consumer although the consumer receives direct incentives from the government. Similar to Scenario 3 where incentivizing hydrogen production made it more cost-effective for the consumer to reduce emissions, in Scenario 4 incentivizing the charging infrastructure leads to a lower emission reduction cost for the energy consumer compared to the direct incentive for battery-powered forklift purchase.

As can be seen in Figure 4-22, recharging infrastructure has a negligible effect on the total cost (less than 2%) while electricity purchase accounts for 10% of the cost. The rest of the cost is attributable to forklift purchase, recharging, and maintenance. Figure 4-22 also shows that battery maintenance and labor cost of recharging account for about 40% of the emission reduction cost. The high labor cost of recharging is due to the frequent need for replacing batteries which is a result of long charging time. As a result, battery charging time and capacity are the main areas that need development to reduce the cost of replacing diesel forklifts with battery-powered forklifts.

4.4 Discussion

Table 4-35 compares the cost of emission reduction for the energy consumer in all scenarios and cases. Values in Table 4-35 show that the least expensive ways to reduce emissions considering the cost burden for the consumer are first: replacing natural gas plants with wind and solar, second: using current surplus power for Power-to-Gas and battery-powered forklifts, and third: replacing current grid mix with wind and solar. These values suggest that in a region where electricity is supplied with fossil fuel-based generation capacity, the most cost-effective way to reduce GHG emissions is to replace fossil fuel plants with renewable technologies rather than reducing emissions in the transportation sector, for instance. However, after the penetration of emission-free electricity reaches a certain percentage, alternative methods of reducing emissions by using clean surplus power should be taken into account. These alternative methods include short-term energy storage in batteries and short-term and seasonal energy storage via hydrogen.

Table 4-35. Cost of emission reduction for the energy consumer in all scenarios and cases

Scenario and Case	**Cost of emission reduction for the energy consumer (CAD per tonne CO_{2e})**
Scenario 1, Case 1: Wind power replacing natural gas power plants	59.76
Scenario 1, Case 2: Wind power replacing Ontario's electricity mix	1479.39
Scenario 2, Case 1: Solar power replacing natural gas power plants	92.18
Scenario 2, Case 2: Solar power replacing Ontario's electricity mix	2418
Scenario 3, Case 1: Power-to-Gas with government incentive for the energy hub operator	431.76
Scenario 3, Case 2: Power-to-Gas with government incentive for the energy consumer	225.20
Scenario 4, Case 1: Battery-powered forklifts with an incentive for infrastructure	447.52
Scenario 4, Case 2: Battery-powered forklifts with an incentive for the energy consumer	317.44

As already mentioned, in this study we consider two ways of using surplus electricity in Ontario:

1. Using surplus electricity to generate hydrogen (Power-to-Gas); and
2. Using surplus electricity to charge battery-powered forklifts.

Surplus electricity is generated in Ontario in two different methods:

1. The difference between supply in off-peak and on-peak hours mostly from nuclear and hydro generation, and;

2. The difference between electricity supplies in different seasons due to wind generation variation.

The results of this study show that using surplus electricity to charge forklifts and using surplus electricity to produce hydrogen may each have unique advantages depending on the assumptions made.

The three advantages of using direct surplus electricity over producing hydrogen are:

1. Higher efficiency;
2. Lower upfront cost; and
3. Compatibility with the surplus electricity currently available in Ontario.

Higher efficiency: Using direct surplus electricity is more efficient than using hydrogen. The lower efficiency of using hydrogen is due to the electrolyzer efficiency and fuel cell efficiency (if used). Surplus electricity has to go through a conversion process of about 60-70% efficiency in the electrolyzer to be converted to hydrogen. If that hydrogen is being used as a fuel for transportation, it has to go through the efficiency of a fuel cell to generate electricity which is about 60% [126]. Using direct surplus electricity is more efficient as electricity is used directly to fuel the vehicle. Therefore, only battery efficiency is applicable here (except for the electric motor efficiency which is common in both technologies). The efficiency of a Li-ion battery is about 85% [112].

Lower cost: Using direct surplus electricity is also less expensive than using hydrogen. Using direct electricity doesn't need conversion technologies (unlike hydrogen that needs electrolyzer and fuel cell). Additionally, the charging infrastructure for charging electric vehicles is less expensive than hydrogen refueling infrastructure (shown in Table 4-6). The cost associated with batteries (maintenance, replacement, labor cost) in battery-powered electric forklifts is higher than hydrogen forklifts.

Types of surplus electricity available in Ontario: The difference in electricity supply between off-peak and on-peak hours each day is because of the nuclear and hydropower generation in Ontario. Nuclear and hydro plants are baseload generating units that operate in a limited range of capacity factor in a year (compare Figure 4-25 and Figure 4-26 for nuclear and hydropower to Figure 4-27 and Figure 4-28 for wind and solar).

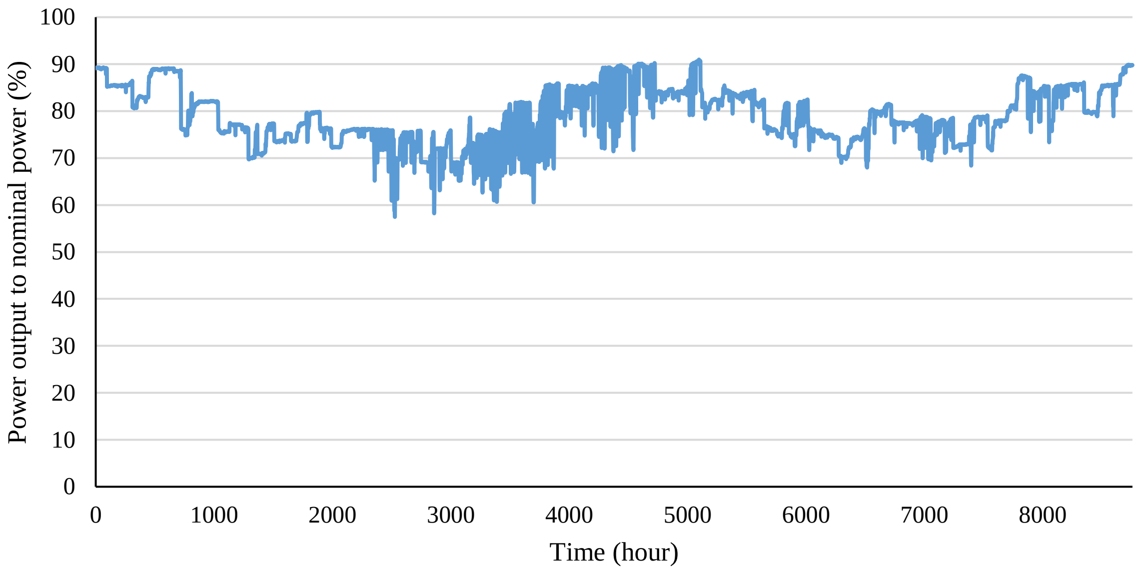


Figure 4-25. Variation of nuclear electricity output in Ontario in 2017 (data from [118])

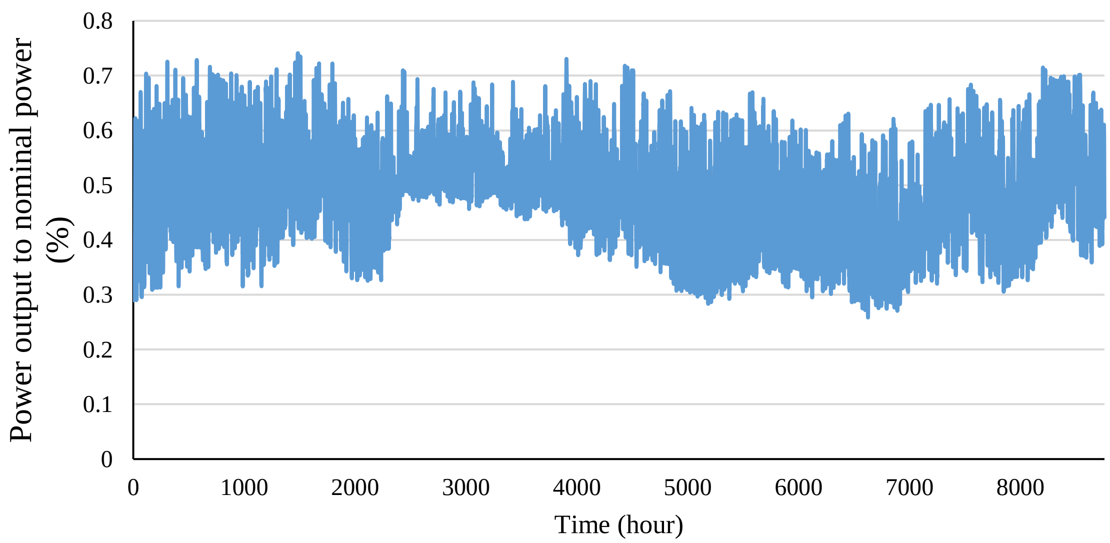


Figure 4-26. Variation of hydropower output in Ontario in 2017 (data from [118])

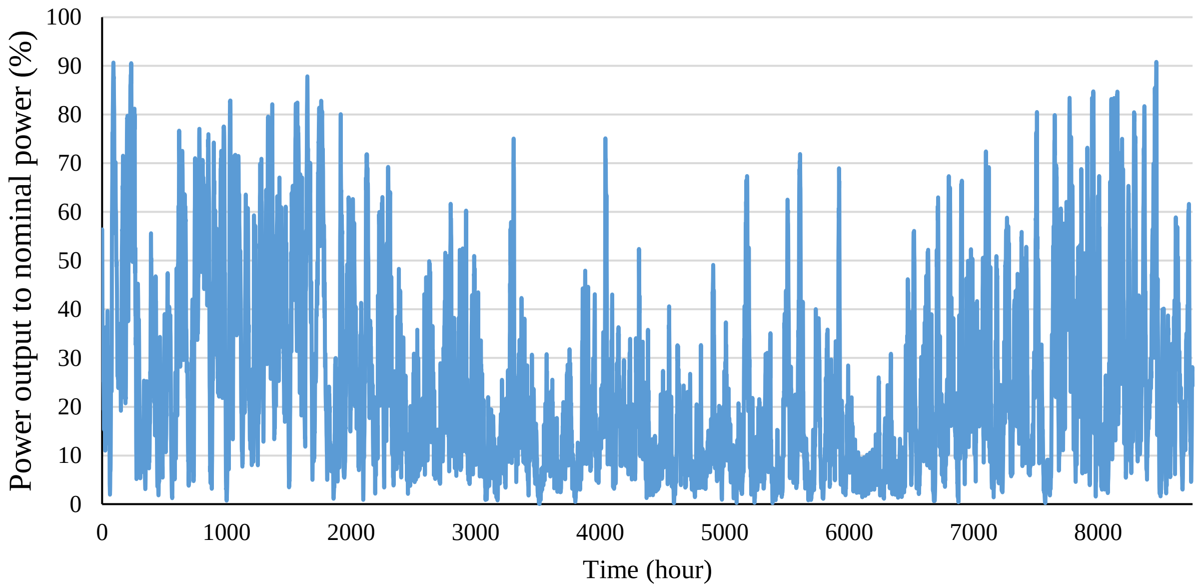


Figure 4-27. Variation of wind electricity output in Ontario in 2017 (data from [118])

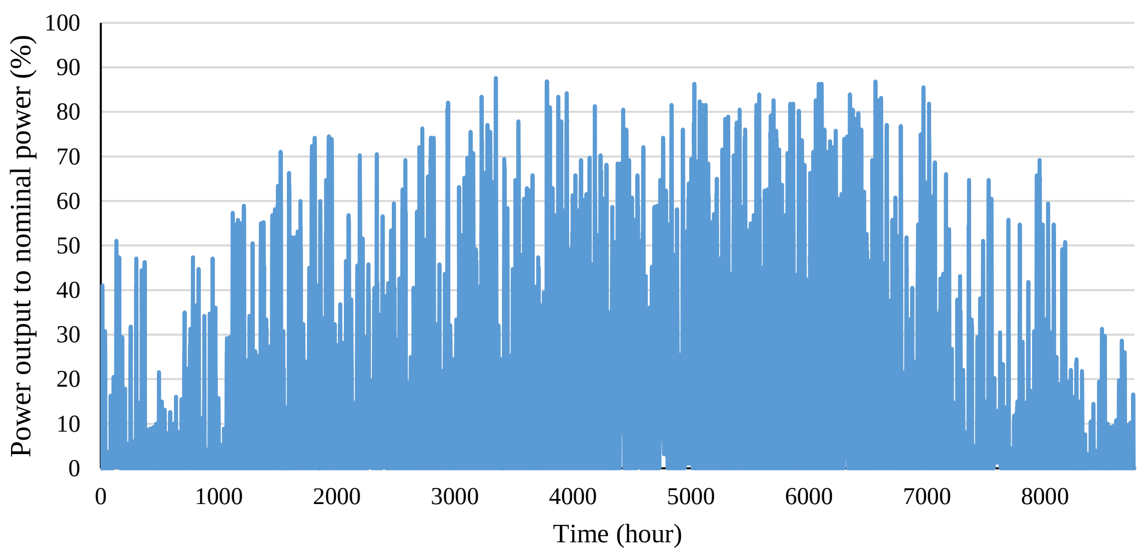


Figure 4-28. Variation of solar electricity output in Ontario in 2017 (data from [118])

The variations in generation output of nuclear and hydropower technologies are due to seasonal demands (compare Figure 4-25 and Figure 4-26 to Figure 4-29 which shows the hourly electricity demand in Ontario).

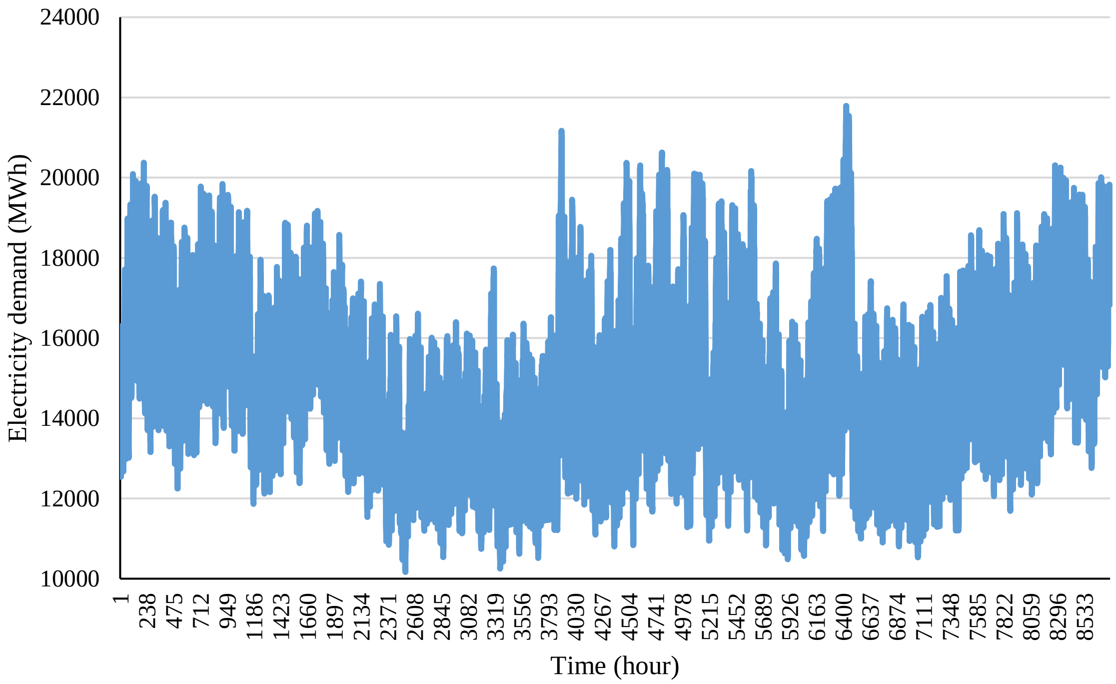


Figure 4-29. Hourly Ontario hourly electricity demand (data from [118])

Both nuclear and hydro generation capacity have a stable capacity factor during a season. However, off-peak electricity demand is significantly lower than on-peak and mi-peak demand in Ontario. Table 4-36 shows the difference between nuclear, hydro, and gas electricity generation and demand in off-peak, mid-peak, and on-peak hours in Ontario. Table 4-36 shows that in off-peak hours, nuclear, hydro, and natural gas capacity create a surplus in Ontario in all months except February and March. Note that in February and March, wind power is at its highest generation output in Ontario as shown in Figure 4-27.

This surplus is available overnight and not seasonally. Nuclear generation capacity is needed to supply the mid-peak and off-peak demand. However, these units have low flexibility and have to operate at their mid-peak, and on-peak hours level in their off-peak hours too. The difference in electricity demand in off-peak and other hours in Ontario creates the off-peak surplus power.

Table 4-36. Average nuclear, hydro, and gas electricity generation minus average demand in off-peak, mid-peak, and on-peak hours in Ontario in 2017 (data from [118])

Month	Average nuclear, hydro, and gas electricity generation minus average demand in off-peak hours (MWh)	Average nuclear, hydro, and gas electricity generation minus average demand in mid-peak hours (MWh)	Average nuclear, hydro, and gas electricity generation minus average demand in on-peak hours (MWh)
January	131	-609	-609
February	-488	-902	-902
March	-593	-1017	-1017
April	880	-66	-66
May	925	-15	-15
June	937	211	211
July	746	-72	-72
August	503	-4423	-443
September	293	-477	-477
October	555	-552	-552
November	109	-188	-188
December	323	-194	-194

Off-peak, mid-peak, and on-peak hours have been determined using Table 4-9.

When wind power is added to the nuclear, hydro, and gas power values, Ontario has surplus electricity at all hours. However, the surplus at off-peak hours is always (in all months) greater than the surplus in mid-peak and off-peak hours. Table 4-37 shows that the summed up generation of nuclear, hydro, wind, and gas capacity creates a surplus in all hours and seasons in Ontario. As Table 4-37 shows, surplus power in April, May, and June is higher than in August, September, and October at all hours. This difference is due to the demand variation as well as intermittent power generation in Ontario which provides seasonal surplus power in the province.

Table 4-37. Average nuclear, hydro, gas, and wind electricity generation minus average demand in off-peak, mid-peak, and on-peak hours in Ontario in 2017 (data from [118])

Month	**The average sum of nuclear, hydro, gas, and wind electricity generation minus average demand in off-peak hours (MWh)**	**The average sum of nuclear, hydro, gas, and wind electricity generation minus average demand in mid-peak hours (MWh)**	**The average sum of nuclear, hydro, gas, and wind electricity generation minus average demand in on-peak hours (MWh)**
January	1508	851	1023
February	1328	922	670
March	882	802	658
April	1721	1183	1021
May	1596	818	969
June	1672	918	827
July	1250	396	221
August	1149	222	82
September	806	101	38
October	1504	670	680
November	1312	1122	973
December	1506	1343	1323

When surplus electricity is always available at off-peak hours, it can be used to charge battery-powered vehicles that can operate on the next day without a need for charging. This was our assumption for modeling the use of surplus electricity to run battery-powered forklifts. We assumed enough electricity is stored overnight to operate the forklift during the day. This solution seems very promising in Ontario because of the nuclear power generated in the province. Currently more than 60% of electricity in Ontario is supplied by nuclear power, which has a much more stable capacity factor compared to other generation technologies in the province. In other words, the lower hanging fruit for using Ontario's surplus electricity is using it at off-peak surplus power to run vehicles on mid-peak and on-peak hours.

Although the discussed arguments were in favor of the direct use of surplus electricity, there are arguments which show the necessity of investing in hydrogen infrastructure for using surplus electricity and address the limits of off-peak battery energy storage. These arguments are:

1. **The type of available surplus electricity in Ontario may change:** Currently, surplus electricity in Ontario is dominated by nuclear and hydro generation technologies. However, with the shutting down of nuclear generation units, wind power will play a more important role in providing electricity in Ontario. This means that the surplus will lose its off-peak and on-peak characteristic and will change more seasonally. Taking advantage of seasonal variation in clean electricity generation is possible with a technology that is capable of storing large amounts of power for long durations of time. As a result, hydrogen will gain an advantage over batteries since batteries are not able to store seasonal surplus electricity.

2. **Multiple applications of a Power-to-Gas system gives it more flexibility over battery storage:** The only well-established application of stored surplus electricity is in electric transportation. However, the transportation sector is not the only sector in Ontario with GHG emissions. Figure 4-2 shows the industry and building account for considerable shares of Ontario's total GHG emission in 2013. Natural gas is a widely-used energy carrier in these sectors. Natural gas accounted for 58.6% of energy consumption in the residential sector in 2013, and this percentage increased to 61.3% in 2015 [127]. Ontario's long-term energy plan also recognizes natural gas as a major source for space and water heating applications [128]. Hydrogen can be used as HENG to reduce GHG emissions in natural gas applications. Although technologies such as air-source heat pumps are also able to reduce emissions in the natural gas application, HENG seems a promising option considering the natural gas infrastructure in Ontario. Hydrogen can also be used in the transportation sector as well as electricity generation.

3. **The mismatch between the surplus electricity and gasoline consumption profile in Ontario is a drawback for battery energy storage for use in the transportation sector:** Replacing an electricity mix with natural gas power plants with renewable sources is considerably less expensive than replacing the current electricity mix. The same argument is valid for electric vehicle deployment. Using off-peak surplus electricity to charge electric vehicles is limited by both surplus electricity available and infrastructure needs. In other words, when current off-peak available surplus electricity is utilized for charging vehicles, new electric vehicle fleet will need

more generation capacity and probably upgraded infrastructure. As a result, hydrogen is more beneficial than battery electricity storage since using hydrogen energy doesn't need additional generation capacity, upgraded infrastructure, and the application is not limited to one sector. Figure 4-30 shows the monthly gasoline consumption in Ontario. As can be seen in Figure 4-30, the months with high gasoline demand are May, June, July, and August.

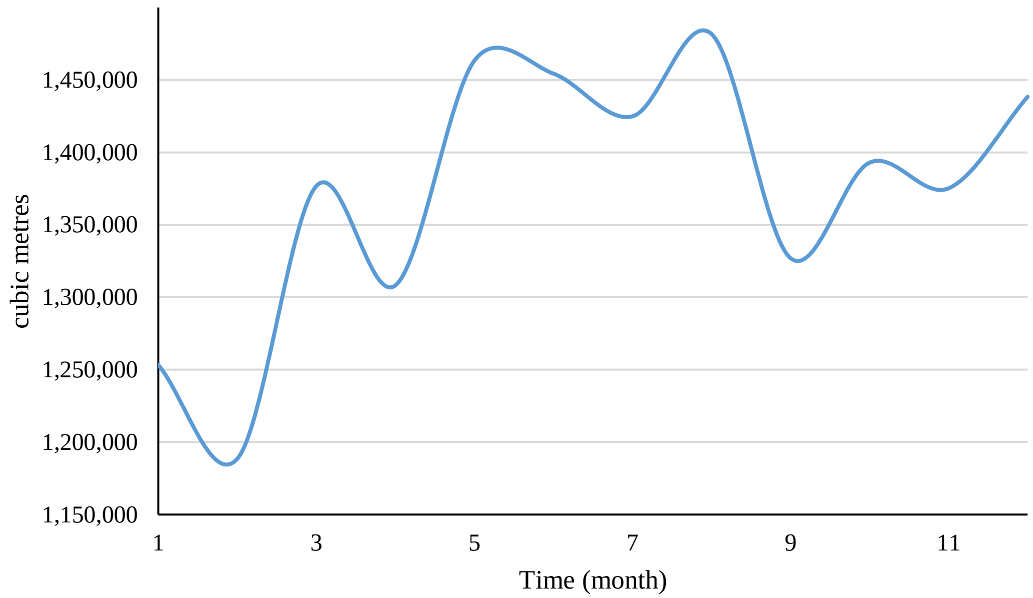


Figure 4-30. Ontario motor gasoline domestic sales in 2017[129]

Figure 4-31 shows surplus electricity in Ontario at off-peak, on-peak, and mid-peak hours as well as the average of all time periods. As can be seen, surplus electricity is lowest during July, August, and September.

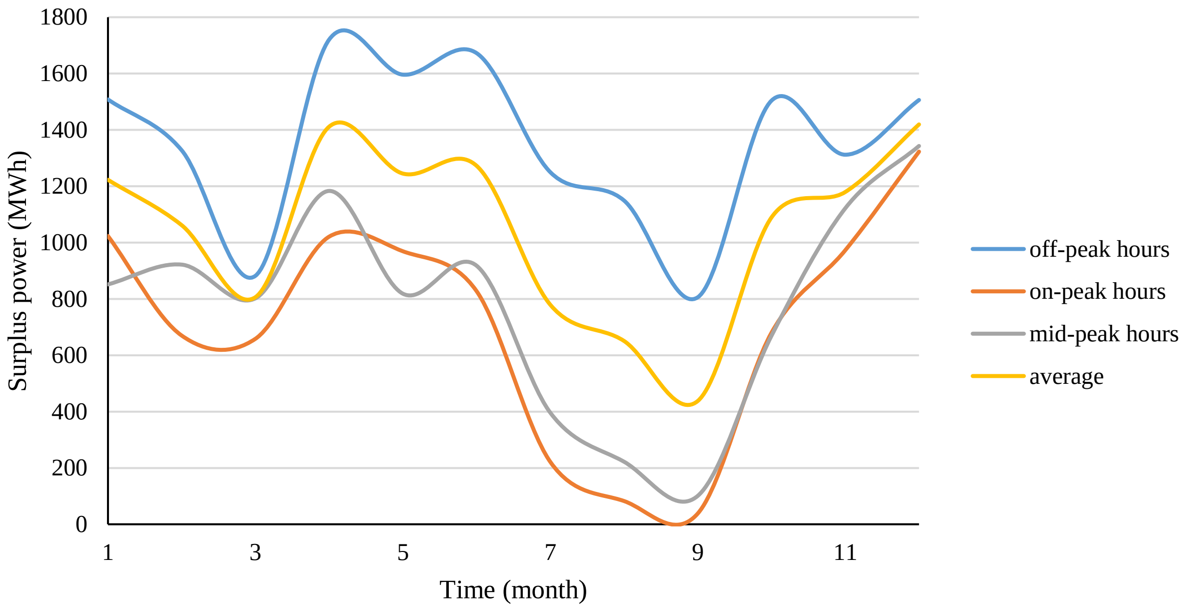


Figure 4-31**.** Surplus electricity in Ontario in 2017 (data from [118])

As can be seen, surplus electricity and transportation fuel demand curves do not match. High surplus electricity is not necessarily available at times of high transportation fuel demand. This mismatch underlines the importance of seasonal storage of energy in the transportation sector. Hydrogen, however, can match the supply and demand patterns. Figure 4-32 shows the underground hydrogen storage level in Scenario 3: Power-to-Gas.

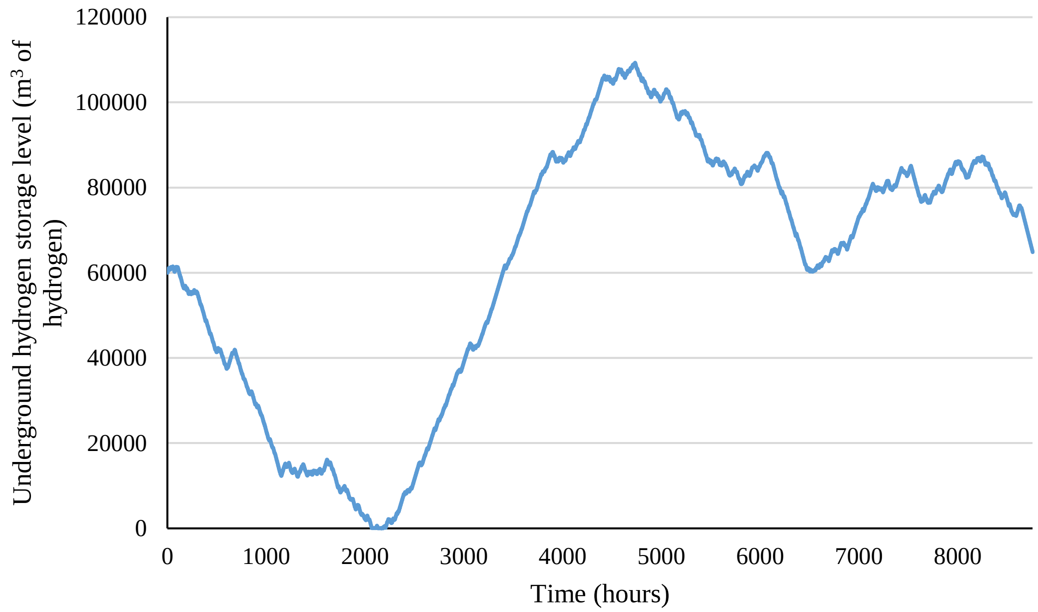


Figure 4-32. Underground hydrogen storage level in Scenario **3**: Power-to-Gas

Comparing Figure 4-32 and Figure 4-29 shows that hydrogen storage is controlled via electricity price signal and it matches the trend of the electricity demand. When the electricity demand in Ontario is low, hydrogen is stored underground and is used at times of high electricity demand to avoid electricity purchase.

In the short term, using surplus electricity to charge electric vehicles seems to be the easiest and most feasible method for reducing emissions in Ontario. However, in mid-term and long-term, when the number of electric vehicles increases and the need for reduction of emissions from natural gas use becomes more important, the role of hydrogen and Power-to-Gas systems becomes more important. Although battery storage and electric vehicle are good matches for surplus nuclear and hydropower, Power-to-Gas can be used to control the variations of wind and solar energy. That is why Ontario needs investment in Power-to-Gas systems right now to be able to manage surplus wind power generation in the future.

Considering the advantages of both direct uses of surplus power and hydrogen production, the research question is not “which technology is better” anymore. The research question is “what combination of direct use and hydrogen production technologies is optimum for development in Ontario”. This question is to be addressed in future works.

4.5 Conclusion

This study aims at addressing the gaps in the energy incentives literature. In this study, we investigate the interaction of all stakeholders in an energy system considering the externalities of energy incentives allocated by the government including their health impacts and their effects on the economic performance of the energy hub operators and consumers as reflected in their taxes. The effect of incentives on the cost-efficiency of energy generation and energy storage is analyzed and compared. Subsequently, a comparison of battery storage and hydrogen storage in Ontario is presented.

Two streams of energy incentives are considered in this study: incentives for the development of renewable power technologies (wind and solar) and energy incentives for technologies using surplus and clean energy in Ontario to reduce GHG emissions (Power-to-Gas and battery-powered forklifts). The results show that when there is an electricity grid with fossil fuel-based electricity generation technologies (natural gas plants were considered here), replacing the grid with wind and solar technologies is the most cost-effective way to reduce GHG emissions. However, considering the current Ontario's electricity mix, incentives for the Power-to-Gas and battery-powered technologies are more cost-effective ways to reduce emissions compared to replacing the grid with wind and solar power technologies. The health impacts associated with natural gas consumption and diesel fuel have a significant effect on reducing the cost of GHG emission reduction for the government. The analysis in this study shows that direct use of electricity and using surplus electricity to produce hydrogen are both important for reducing emissions as each of these methods has their unique advantages. The remaining question to be investigated in the future is what combination of these methods is optimum for reducing GHG emissions in Ontario in the most cost-effective way.

5 Assessing the potential of surplus clean power in reducing GHG emissions; a game theory approach

The following section is based on work, by Haghi, E., Shamsi, H., Dimitrov, S., Fowler, M., Raahemifar, K., accepted for publication in the International Journal of Hydrogen Energy, and work by Haghi et.al [130], published in IET Energy Systems Integration. Contribution of authors is detailed in the Statement of Contributions section.

5.1 Assessing the potential of fuel cell-powered and battery-powered forklifts for reducing GHG emissions using clean surplus power

The following section is based on work, by Haghi, E., Shamsi, H., Dimitrov, S., Fowler, M., Raahemifar, K., accepted for publication in the International Journal of Hydrogen Energy.

5.1.1 Introduction

5.1.1.1 Application of hydrogen for energy storage

Hydrogen as an energy carrier can provide large-scale seasonal storage which makes it a noticeable storage medium for the introduction of renewable power generation technologies into energy systems [131]. Ehret and Bonhoff [132], stated that hydrogen production by renewable energy could be a primary contributor to Germany's Energiewende for the transition to a renewable energy supply system. Analyzing the application of hydrogen in energy storage systems and comparing its effectiveness with other storage technologies such as batteries is an area of interest in the literature. Shamsi et al. [133], for instance, developed a model for minimizing the cost of emission reduction in an industrial facility using wind, solar, fuel cell, hydrogen storage, and battery technologies. Authors in [133] stated that a wind/fuel cell/hydrogen storage/battery hybrid system is more cost-effective in reducing Greenhouse Gas (GHG) emissions compared to a wind-alone or solar-alone system. Colbertaldo et al. [134], developed a model for simulating power systems to assess the effectiveness of hydrogen in balancing supply and demand in systems with high penetration of renewable technologies. Authors in [134] compared the cost-effectiveness of hydrogen and battery storage systems and concluded that hydrogen systems are more cost-effective storage technologies compared to batteries. Reviewing the research on comparison of energy storage technologies shows that each storage technology has unique characteristics which makes them suitable for different applications [135][136][137].

5.1.1.2 Application of hydrogen in replacing fossil fuels in internal combustion engines

An advantage of hydrogen energy storage systems is that stored electricity in the form of hydrogen can be used for replacing fossil fuel consumption in different applications. One of the most noted of these applications is replacing fossil fuels in internal combustion engines (ICEs). The application of hydrogen in fuel cell vehicles (FCVs) for replacing ICEs has been suggested as a promising pathway in reducing GHG emissions [138][139][140]. Paster et al. [141], even suggested that FCVs have the potential to be as cost-effective as gasoline vehicles. Liu et al. [138], assessed the impact of using FCVs on GHG emissions from road transport in China and suggested FCVs should be considered as a viable option alongside battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) for reducing GHG emissions in the transportation sector. An analysis by Michalski et al. [142], showed that a mix of BEVs and FCVs is the optimal solution for reducing GHG emissions in the transportations sector and both these technologies are effective when planning for future transportation systems. A significant increase in the number of hydrogen refueling stations and infrastructure in recent years has also been reported in the literature [143]. From their foresee review of hydrogen transportation systems, Tanç et al. [144], stated that the demand for hydrogen-based transportation technologies would increase in the 2030-2050 period due to continuous progress in cost decrease, efficiency improvement and the development of refueling infrastructure.

Fuel cell-powered forklift is another technology by which fuel cells can replace ICEs in a Power-to-Mobility framework [145][146]. Fuel cell-powered forklifts are recognized as the most successful application of hydrogen-based technologies in the transportation sector [147]. Distinguished by their powertrain, forklifts are divided into different categories including but not limited to: liquefied petroleum gas (LPG) forklifts, diesel forklifts, battery-powered forklifts, and fuel cell-powered forklifts. Diesel forklifts are a popular option among industries due to their specifications such as durability [93]. However, characteristics such as zero on-site emission and low noise pollution have made battery-powered forklifts a popular choice [93]. Fuel cell-powered forklifts share these characteristics with battery-powered forklifts [94]. Lower refueling time (which leads to less idle time), constant power generation, and potential of fuel cell-powered forklifts for reducing GHG emissions are other advantages of fuel cell-powered forklifts [148][95][96]. The short refueling time not only reduces the need for energy storage but also decreases the labor cost associated with operating fuel cell-powered forklifts compared to other technologies [149].

Fuel cell-powered forklifts are more developed hydrogen-based technologies compared to hydrogen buses and trucks, and it is predicted that their market may grow significantly due to their advantages such as short refueling time [150]. Developing hydrogen forklift demonstration projects is considered as a measure for large-scale deployment of hydrogen infrastructure in Europe [151]. Demonstration and research projects focused on fuel cell-powered forklifts operation and technology have also been done in other countries such as Turkey and South Africa [152][153]. These advantages and prospects have attracted attention toward research on fuel cell-powered forklifts in recent years and operation of fuel cell-powered forklifts have been studied in the literature from different aspects. Houf et al. [154], and Ekoto et al. [155], for instance, studied hydrogen release in a warehouse where fuel cell-powered forklifts are operated based on a safety point of view. Hosseinzadeh et al. [156], on the other hand, studied the operation of a fuel cell/battery hybrid forklift by analyzing different system configurations to find the most economical system for a hybrid forklift based. Analyzing fuel cell-powered forklifts from another aspect, Liso et al. [157], studied temperature variation in a fuel cell system used in a forklift. Domínguez et al. [158], studied the dynamic behavior of fuel cell-powered material handling and transportation fleet in a company in Madrid, Spain. The authors in [158] used TRNSYS to analyze the flow of energy and operation of energy conversion and storage technologies in the case study. Fuel cell-powered forklifts are also among promising hydrogen-based technologies that are studied in literature focused on the analysis of hydrogen-powered communities such as the work done in [159][160][161].

Despite all the research backing the advantages of fuel cell-powered technologies, assessing the profitability of such systems for end users is still a knowledge gap in the literature and the work done in this area is very limited. An analysis by Renquist et al. [99], for instance, showed that depending on the type of facilities and workloads, fuel cell-powered and battery-powered forklifts can provide advantages and fuel cell-powered forklifts are suitable for applications with high workloads. Similar work, however, is rare in the literature. At the same time, while there is a consensus in the literature on the role of hydrogen in future energy systems, deployment of hydrogen energy systems and the potential of hydrogen in reducing GHG emissions in different energy sectors depend on multiple factors including hydrogen production method, hydrogen storage and fuel cell cost, and role of stakeholders in a hydrogen supply chain which have to be further investigated. Acar and Dincer [162], for instance, stated that the production of hydrogen from renewable sources is essential to the effectiveness of hydrogen as a clean fuel. Ren et al. [163] analyzed different hydrogen pathways against criteria such as availability, accessibility, affordability, and energy security. By comparing different hydrogen pathways, Ren et al. [163], stated that the hydrogen production method affects cost-effectiveness and energy security of a country. Producing hydrogen via electrolysis using wind and solar power, for instance, is more preferable compared to nuclear-based hydrogen production and fuel-based hydrogen generation when evaluated against the considered criteria [163].

5.1.1.3 Game theory and multi-stakeholder analysis of hydrogen energy systems

As already stated, multi-stakeholder analysis and high cost are crucial factors in the development of hydrogen energy systems. Ren et al. [164], stated that the role of different stakeholders and decision-makers is a critical aspect for the development of a hydrogen supply chain. Providing tools for stakeholders to better understand and assess different aspects of a hydrogen supply chain system is then vital for the deployment of such systems [165]. However, the literature focused on assessing the role of different stakeholders and modeling their interaction in the hydrogen supply chain is limited [166], and includes mostly qualitative methods. In one study in this area, Ren et al. [167], developed a multi-stakeholder qualitative model for assessing the sustainability of hydrogen production via biomass-based technologies in their work. Criteria authors used in [167] included economic, environmental, technological and social-political aspects of hydrogen production.

To fill the gap in this area, modeling the interaction of stakeholders active in an energy system and engaged in hydrogen energy projects is a necessity. Analyzing the interaction of stakeholders for developing a hydrogen-based energy system can also help better address the higher cost of such systems compared to conventional systems. In that sense, game theory is a suitable modeling concept for addressing the challenge of modeling stakeholder interaction in an energy system. Game theory deals with the interaction of two or more decision-makers who act rationally while their actions affect each other [168]. Game theory has been used widely in three main areas of research in energy systems including electricity dispatch problems, demand-side management problems, and electric vehicle (EV) charging problems. In the electricity dispatch area, Kou and Park [169], developed a game theory model to analyze the interaction of microgrids and a utility for energy trading. The authors in [169], used a two-layer approach including a Nash game to formulate the non-cooperative interaction of microgrids and a Stackelberg game for determining the energy price by the utility and the microgrids. In the demand-side management area, Mohsenian-Rad et al. [170], developed a game theory formulation to model the interaction of users for energy scheduling to minimize the energy costs where energy consumers were the players in the game. In electric vehicle (EV) charging area, Wu et al. [171], developed a game theory model for analyzing the behavior of EVs in interaction with aggregator in providing frequency regulation service to the electricity grid. Aghajani and Kalantar [172], used game theory to model the interaction of electric utility and parking lot operator. The developed model in [172] was a cooperative game model in which the utility aimed at maximizing profit while the parking lot operator's objective was minimizing cost. Zhao et al. [173], used Stackelberg game concept for modeling the interaction of an EV charging facility and EV owner with EV charging facility as the leader and EV owner as the follower.

Application of game theory, however, has not been limited to the three mentioned areas. Game theory has been a popular concept in recent literature and has been used in different forms to address the challenges of energy systems. Budi and Hadi [174], for instance, used game theory for optimal generation expansion planning in deregulated markets. Chen et al. [175], used game theory to analyze the effect of government subsidies on the deployment of energy storage technologies in microgrids. Han et al. [176], used game theory for assessing the economic operation of wind/energy storage systems. Contreras-Ocaña et al. [177] developed a multi-follower Stackelberg game model to analyze the interaction of energy storage operators and energy aggregator in an energy market. Michalski [178], used a Cournot game model to assess the effect of hydrogen storage on the decisions made in the electricity market. Miralinaghi et al. [179], used a bi-level model for optimal location planning of hydrogen refueling stations.

The review of literature in the application of game theory in energy system shows that while different forms of game theory has been used to address some challenges of energy systems such as EV charging and microgrid market participation, it has rarely been used in comparing the cost-effectiveness of battery and hydrogen storage systems and has also not been used in analyzing the cost-effectiveness of fuel cell-powered and battery-powered forklifts.

5.1.1.4 Ontario's energy system

In this study, we are using game theory in analyzing the effect of government policies on reducing CO_2 emissions in Ontario using battery-powered and fuel cell-powered forklifts. Province of Ontario, Canada is the case study of our assessment due to the noticeable share of industry and transportation sectors in GHG emissions in the province. Additionally, Ontario's supply mix, as well as its supply and demand characteristics, show great potential for the deployment of hydrogen storage and fuel cell technologies [11][12][133]. As Figure 4-3 shows, more than 95% of Ontario's electricity mix had a fossil-free source in 2017.

Table 5-1 shows the electricity demand, supply, and surplus data in Ontario in 2017. As can be seen in Table 5-1, Ontario's surplus power in 2017 was more than the transmission-connected power generated from wind, solar, and biofuel plants, combined.

Table 5-1. Electricity demand, transmission-connected supply, and surplus data in Ontario in 2017 (data from [180])

Electricity data	Quantity (TWh)
Total demand in 2017	132.1
Electricity supplied by nuclear	90.6
Electricity supplied by hydro	37.7
Electricity supplied by oil/gas	5.9
Electricity supplied by wind	9.2
Electricity supplied by biofuel	0.4
Electricity supplied by solar	0.5
Surplus electricity (total supply - total demand)	12.2

Market electricity price in Ontario is known as hourly Ontario electricity price (HOEP) which is determined by electricity market clearance. The cost of electricity for consumers in Ontario, however, is not limited to the HOEP. Global adjustment (GA) is another component of the price that energy consumers have to pay and is charged to cover the cost of building new electricity infrastructure in the province, maintaining existing resources, as well as providing conservation and demand management programs [7]. Although the HOEP has generally decreased in recent years in Ontario, GA has increased significantly which has led to a noticeable increase in overall electricity price in the province. At the same time, a significant amount of power is curtailed in Ontario as shown in Table 5-1 or is exported at low prices. In that sense, developing energy storage technologies is recognized as an effective policy for reducing renewable power curtailment [181]. One of the ways government can encourage consumers in using electricity-based technologies instead of fossil fuel-based technologies is totally exempting them from paying GA or in hours of a day when surplus power is available. This policy has been recommended in technical and policy literature. For instance, a report by the Ontario society of professional engineers suggested that surplus power should be made available for energy consumers at wholesale prices [182]. Additionally, a report by the Ontario chamber of commerce, also suggests that surplus power to become available to businesses at export or better than exported prices [183]. In this way, energy consumers can purchase power at lower prices in some hours which reduces the operation cost of electricity-based technologies for them. A lower renewable power curtailment will also reduce GA for energy consumers in Ontario. Additionally, the use of these technologies by energy consumers can lead to GHG emission reduction in Ontario. In this study, we are also analyzing whether battery-powered and fuel cell-powered forklifts are cost-effectiveness technologies for reducing GHG emissions in Ontario. Another objective of this study is assessing if hydrogen and battery storage technologies can benefit all stakeholders in an energy system. There are two stakeholders in our model: government and energy consumer, which is assumed to be an industrial facility. The government can adopt policies that encourage the replacement of diesel forklifts with battery-powered and fuel cell-powered forklifts by the energy consumer. This policy is considered to be in the form of surplus power made available to the energy consumer at a discounted price. The energy consumer is an industrial facility which uses

150 diesel forklifts in their warehouse. The energy consumer, however, may replace diesel forklifts with battery-powered and fuel cell-powered forklifts if it leads to a lower cost.

5.1.2 Methodology

In this study, we are using game theory to assess the cost-effectiveness of battery-powered and fuel cell-powered forklifts in reducing GHG emissions in Ontario. We are considering two stakeholders in our model: the government and the energy consumer, which interact with each other in the energy system. Figure 5-1 shows the system configuration for the energy consumer.

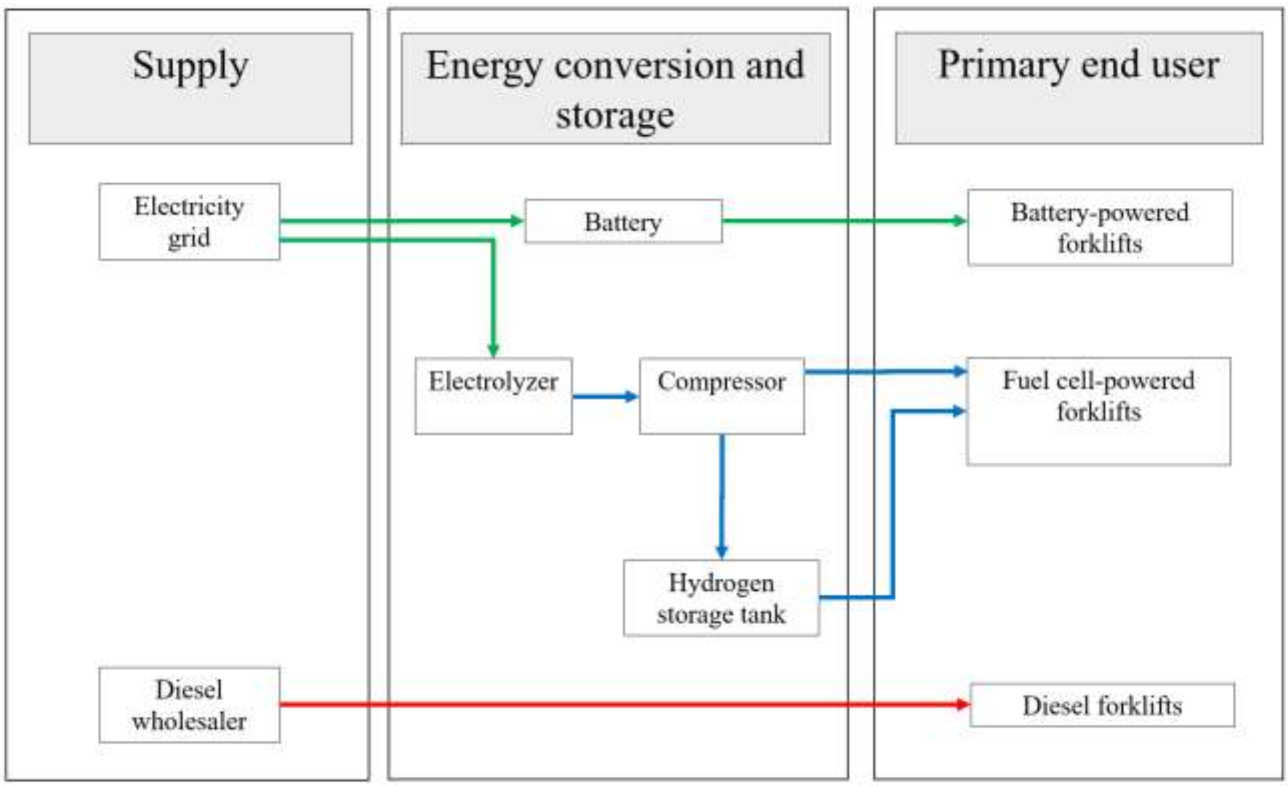


Figure 5-1. The system configuration of the energy consumer

The energy consumer has the options of purchasing electricity from the grid to operate battery-powered forklifts or fuel cell-powered forklifts (to store power in a battery or to produce hydrogen via electrolysis) and using diesel forklifts or a combination of these technologies. The policy the government can pursue is allowing energy consumer to purchase a percentage of Ontario's surplus power at a discounted price which does not include the global adjustment (GA). In other words, the government makes the power available to the energy consumer at the hourly Ontario electricity price (HOEP). In this approach, the government pays two cents per kWh of surplus power the energy consumer purchases to electricity utility companies for covering transmission and distribution cost of the power purchased by the energy consumer. The government has an incentive to adopt this policy as replacement of diesel forklifts with battery-powered and fuel cell-powered forklifts reduces GHG emissions in Ontario which is beneficial to the government as it reduces the social cost of carbon (SCC). The social cost of carbon is used for monetizing the economic cost of a tonne of CO_{2e} emitted to the atmosphere [184]. Effects of an additional tonne of CO_2 emission on different factors including but not limited to agricultural efficiency, floods, human health, ecosystem, and forests are summed up to monetize the SCC [185].

Although calculating SCC bears uncertainty due to the different effects of carbon emissions on human health, agricultural lands, water resources, and coastal zones over an extended period, it is a valuable indicator which can be used by governments and policy-makers to assess the cost-efficiency of their GHG emission reduction programs [185]. Environment and Climate Change Canada has published a document reporting the SCC for Canada which can be found in [186]. In this study, SCC is used in the government's objective as a criterion for assessing the cost-efficiency of government's GHG emission reduction policy.

5.1.2.1 Model description

As already stated, there are two players (stakeholders) interacting with each other in the model: the government and the energy consumer. The government's decision variable is the amount of Ontario's surplus power it makes available to the energy consumer at the hourly Ontario electricity price (HOEP), and the energy consumer's decision variables are the number of diesel forklifts, battery-powered forklifts, and fuel cell-powered forklifts it operates. Figure 5-2 shows the interaction between the government and the energy consumer in our model.

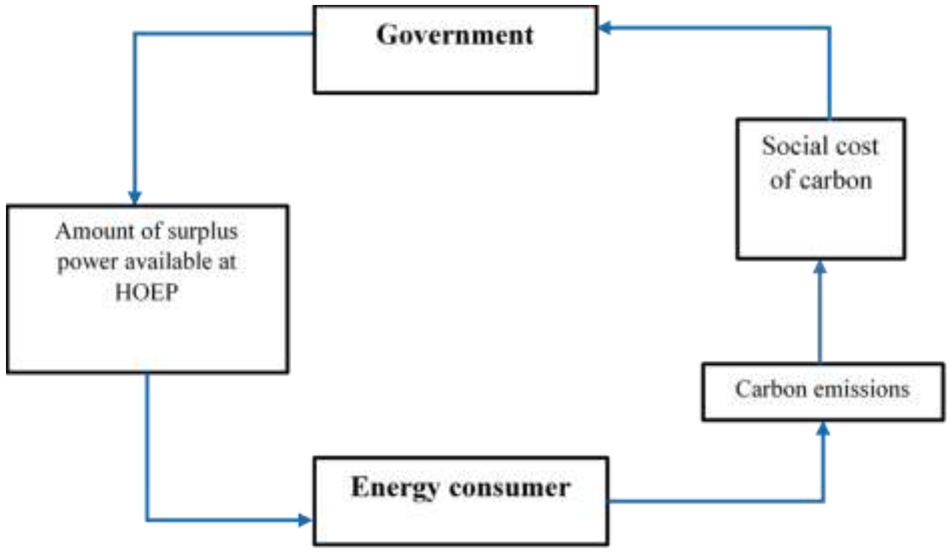


Figure 5-2. Interaction of the government and the energy consumer

As can be seen in Figure 5-2, the government makes a percentage of Ontario's surplus power available to the energy consumer at HOEP to encourage the deployment of alternative forklift technologies. The energy consumer can take advantage of low electricity price that is allocated to them at HOEP to store it in batteries or produce hydrogen and store in hydrogen storage tanks. Stored electricity in batteries or hydrogen in hydrogen storage tank can be used later for operating forklifts when electricity prices are higher. The energy consumer has to pay both HOEP and global adjustment (GA) in other hours of a year when power is not discounted. If diesel forklifts are replaced with battery-powered or fuel cell-powered forklifts, carbon emissions of the industrial facility will reduce which leads to a subsequent decrease in the social cost of carbon for the government.

The government is the leader in this game which moves first and decides about the amount of discounted power that will be made available to the energy consumer at HOEP to minimize its objective function. Knowing the decision of the leader, the energy consumer (the follower) then makes its decision of what type of forklifts to operate in order to minimize its objective function. A bilevel formulation is used in this study to analyze the problem as shown in Equations 5-1 to 5-4.

$$Min\ f(x, y_1, y_2, y_3) \qquad 5\text{-}1$$

$$y\ solves\ Min\ z\ (x, y_1, y_2, y_3) \qquad 5\text{-}2$$

$$subject\ to \tag{5-3}$$

$$x = 0.2a + 0.3b + 0.4c + 0.5d + 0.6e + 0.7f + 0.8g$$

$$a + b + c + d + e + f + g = 1$$

$$y_1 + y_2 + y_3 = 150 \tag{5-4}$$

In Equation 5-1 and Equation 5-2, f and z show the objective functions of the government and the energy consumer as defined in Equation 5-5 and Equation 5-6, respectively. Equation 5-3 and Equation 5-4 represent the set of constraints for the optimization problem. The government's optimization problem is constrained by the value of x the government can choose. Equation 5-3 shows that the government can only choose one of the values of 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, and 0.8 for x. In Equation 5-4, y_1, y_2, and y_3 are the energy consumer's decision variables and show the number of battery-powered forklifts, fuel cell-powered forklifts, and diesel forklifts the energy consumer chooses to operate, respectively. The energy consumer has the constraint of operating 150 forklifts all the time as shown in Equation 5-4.

$$f(x, y) = x \times (Ontario's\ surplus\ power) \times (TDC) - \alpha \times e(y_1, y_2, y_3) \tag{5-5}$$

$$z(x, y_1, y_2, y_3) = y_1 \times (ACL_1 + CRI + LC_1 + CIWS_1 + FLMC_1 + BMC + EC) + y_2 \times (ACL_2 + CFI_2 + LC_2 + CIWS_2 + FLMC_2 + FCMC + HC) + y_3 \times (ACL_3 + CFI_3 + LC_3 + CIWS_3 + FLMC_3 + DC) \tag{5-6}$$

In Equation 5-5, x is the percentage of Ontario's surplus power at each hour that is made available to the energy consumer at HOEP by the government, TDC is the amount of charges paid by the government to cover transmission and distribution charges of discounted power in CAD per kWh (assumed to be two cents per kWh in our model), α is the social cost of carbon in CAD per tonne of CO_2, and e is the emission reduction in tonnes of CO_2. In the optimization formulation shown in Equation 5-1 to Equation 5-6, the percentage of Ontario's surplus power allocated to the energy consumer at the discounted rate (HOEP) is an endogenous parameter of the problem and will be determined when the optimization problem is solved. Amount of emission reduction (e) is a function of the number of battery-powered, fuel cell-powered, and diesel forklifts the energy consumer uses and is calculated based on the mix of forklifts the energy consumer operates.

In Equation 5-6, z is the objective function of the energy consumer defined as the annualized cost of the industrial facility for operating the forklifts in CAD, ACL is the amortized cost of lift in CAD per forklift per year, CRI is the cost of recharging infrastructure of battery-powered forklifts in CAD per forklift per year, CFI is the cost of fueling infrastructure for fuel cell-powered and diesel forklifts in CAD per forklift per year, LC is the labor cost for battery-powered, fuel cell-powered, and diesel forklifts per forklift per year, $CIWS$ is the cost of infrastructure warehouse space for battery-powered, fuel cell-powered and diesel forklifts in CAD per forklift per year, $FLMC$ is forklift maintenance cost for battery-powered, fuel cell-powered and diesel forklifts in CAD per forklift per year, BMC is battery maintenance cost for battery-powered forklifts in CAD per forklift per year, $FCMC$ is fuel cell maintenance cost for fuel cell-powered forklifts in CAD per forklift per year, EC is electricity cost for charging battery-powered forklift in CAD per forklift per year, HC is hydrogen cost for refueling fuel cell-powered forklift in CAD per forklift per year, and DC is diesel cost for refueling diesel forklift in CAD per forklift per year. The assumed values for the parameters in Equation 5-6 are reported in Table 5-2.

EC used in the formulation for the battery-powered forklift is the sum of electricity purchase cost at both discounted and not discounted hours. HC for fuel cell-powered forklift includes the cost of electricity purchased for producing hydrogen, annualized electrolyzer cost, annualized hydrogen storage tank cost, and annualized compressor cost. The optimum size of the electrolyzer, hydrogen storage tank, compressor, and batteries the energy consumer uses are determined by solving the energy consumer's optimization problem. However, the optimum sizes of those technologies are not reported in this study as the results section is focused on the number for forklifts the energy consumer operates. Cost assumptions for electrolyzer, hydrogen storage tank, compressor, and battery technologies are reported in Table 5-3.

Figure 5-3 shows the algorithm used in this study for finding the Nash equilibrium in the game theory problem. Nash equilibrium is a state in a game where none of the players (stakeholders) has an incentive to deviate from. The critical point in this game is that the government has to pay two cents per kWh for covering transmission and distribution charges of discounted power allocated to the energy consumer. In the Nash equilibrium state in this game, the government will allocate the optimum amount of surplus power at HOEP to the energy consumer. With a lower amount of discounted power, the energy consumer will not reduce emissions at the government's desired level while with a higher amount, the government has to pay more transmission and distribution charges that it gains from reduced emissions. As the equilibrium state, the energy consumer will also operate a mix of forklifts that has the lowest cost considering the amount of discounted power they are allowed to purchase. As can be seen in Figure 5-4, the algorithm starts with $i = 1$ representing the lowest x value the leader (the government) can allocate to the energy consumer. f_{best} (the minimum value for the leader's objective function) is considered to be "big M" which represents a large positive number at the beginning of the algorithm. The follower's objective function for each i (z_i) is minimized knowing the value of x (the government's decision variable). After solving the follower's problem, the government's objective function (f_i) is calculated. f_{best} is updated if a lower value for government's objective function is found. The algorithm ends when all the possible values of x have been used for calculating the government's objective function. The index n represents the highest value of x the government can take.

In the algorithm shown in Figure 5-3, x (the percentage of surplus power that is allocated to energy consumer at HOEP) may have the values of 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, and 0.8.

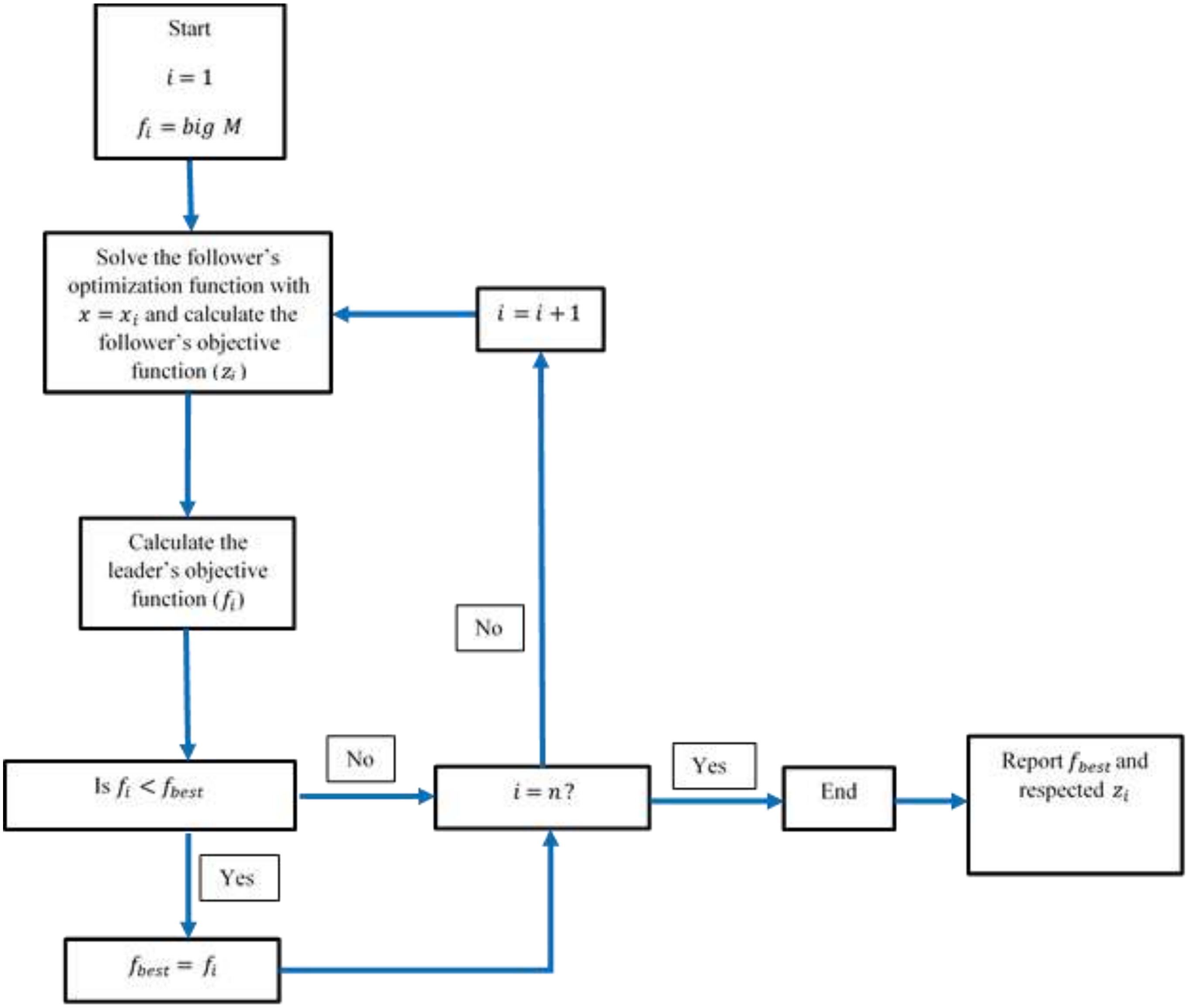


Figure 5-3. Algorithm for solving the game theory model

Mixed Integer Program (MIP) solver in General Algebraic Modeling System (GAMS) is used for solving the optimization problem. MIP was used in this study as the number of battery-powered, fuel cell-powered, and diesel forklifts are integer values.

5.1.2.2 Model inputs

In this section, input data to the model including different forklift characteristics, fuel cost, and electricity and hydrogen storage technology characteristics are presented. Table 5-2 shows the cost of fuel cell-powered, battery-powered, and diesel forklift used in the model and used in Equation 5-6.

Table 5-2. Assumed fuel cell-powered, and battery-powered and diesel forklift associated costs (All values 2011 USD except stated otherwise) [187]

	Fuel cell-powered forklift	**Battery-powered forklift**	**Diesel forklift**
Amortized cost of lift (ACL) in 2011 USD per forklift per year	2800	2800	Not applicable as the energy consumer has already paid for the diesel forklifts
Cost of fuel/recharge infrastructure (CRI, CFI) in 2011 USD per forklift per year	3700	1400	Assumed to be 2000 CAD per lift.
Labor cost (LC) for battery charging/H_2 refueling in 2011 USD per forklift per year	800	4400	800 (Same as the cost for fuel cell-powered forklifts)
Cost of infrastructure warehouse space ($CIWS$) in 2011 USD per forklift per year	500	1900	500 (Same as the cost for fuel cell-powered forklifts)
Forklift maintenance cost ($FLMC$) in 2011 USD per forklift per year	2800	2800	2800 (similar to fuel cell-powered and battery-powered forklifts)

Battery/fuel cell maintenance cost ($BMC, FCMC$) in 2011 USD per forklift per year	2200	3600	Not applicable

One kg of hydrogen is assumed to be used to power a fuel cell-powered forklift for every 15 kWh of power to battery-powered forklift wheels. 15 kWh to the wheels is equivalent to 24 kWh of electricity from the wall for powering a battery-powered forklift [115]. Another assumption is that 0.16 gallon of diesel is needed to operate a diesel forklift for every kWh of electricity delivered to a battery-powered forklift [115]. The power consumption rate of battery-powered forklift is assumed to be 2.85 kW per hour [113]. The battery charge rate is from values reported in [113]. The total purchased electricity from the industrial facility equals the sum of power purchased for producing hydrogen and the power purchased for charging battery-powered forklifts' batteries. HOEP values for the year 2017 is taken from [188], and GA is assumed to be 10 cents per kWh.

Table 5-3 shows the assumed cost of the electrolyzer, compressor, hydrogen storage tank, and battery technologies considered in this study. All values are in 2017 CAD.

Table 5-3. Assumed cost of electrolyzer, compressor, and hydrogen storage tank technologies

Technology	**Capital cost (2017 CAD)**	**Annual O&M cost**
Alkaline Electrolyzer	1076 (CAD per kW) [70]	Assumed to be 4% of the capital cost (CAD per kW per year)
Electrolyzer stack replacement	30% of electrolyzer capital cost	Included in electrolyzer O&M cost
Compressor	$51605 \times \left(Capacity, \frac{kg}{hr}\right) + 23282$ [71]	Assumed to be 4% of the capital cost (CAD per year)
Hydrogen storage tank	1200 CAD per kg of H_2 [71]	Assumed to be 4% of the capital cost (CAD per kg of H_2 per year)

Battery	723 (CAD per kWh) [112]	Assumed to be 1% of capital cost (CA per kWh per year)

Diesel price is assumed to be 1.075 CAD per liter in this study based on values taken from [116]. CO_2 emission from diesel combustion is assumed to be 10.18 kg of CO_2 per gallon of diesel [122].

5.1.3 Results and discussion

In this section of the study, the results of the game theory optimization model are presented. Table 5-4 shows the results of the optimization problem for the different social cost of carbon (SCC) values. The government's and energy consumer's objective function, the value of x, and the number of diesel, battery-powered, and fuel cell-powered forklifts energy consumer operates are reported in Table 5-4.

Table 5-4. Optimization results for different SCCs

SCC (2017 CAD per tonne of CO_2)	The leader's (Government's) objective function (f_{best}) (2017 CAD)	x	The follower's (Energy consumer's) objective function (z_i) (2017 CAD)	Number of battery-powered forklifts (y_1)	Number of fuel cell-powered forklifts (y_2)	Number of diesel forklifts (y_3)
0	0	0	3,857,724	0	0	150
10	0	0	3,857,724	0	0	150
20	-3,396	0.1	3,842,398	31	0	119
30	-46,208	0.6	3,752,954	91	54	5
40	-105,661	0.6	3,752,954	91	54	5
50	-165,114	0.6	3,752,954	91	54	5
60	-224,567	0.6	3,752,954	91	54	5
70	-284,020	0.6	3,752,954	91	54	5
80	-343,473	0.6	3,752,954	91	54	5
90	-402,926	0.6	3,752,954	91	54	5
100	-462,379	0.6	3,752,954	91	54	5
110	-522,358	0.7	3,736,715	68	82	0

120	-583,861	0.7	3,736,715	68	82	0
130	-645,364	0.7	3,736,715	68	82	0
140	-706,867	0.7	3,736,715	68	82	0
150	-768,370	0.7	3,736,715	68	82	0

As can be seen in Table 5-4, the government's objective function has a value of zero for SCC of zero and 10 CAD per tonne of CO_2. The Nash equilibrium state for games with those SCC values is where the government allocates no discounted power to the energy consumer, and the energy consumer does not reduce emissions and keeps using its 150 diesel forklifts. SCC value of lower than 10 CAD per tonne of CO_2 is not high enough for the government incentivize them to pay two cents per kWh for discounted power that is used by the energy consumer to reduce CO_2 emissions. Without the discounted power, the energy consumer is also not willing to invest in replacing diesel forklifts with battery-powered and fuel cell-powered forklifts. As already stated, neither of the players have an incentive to change their current action at the Nash equilibrium point. However, when the SCC increases to 20 CAD per tonne of CO_2, the government will change action and allocates discounted power to the energy consumer. In other words, the benefit of reducing CO_2 emissions for the government is high enough to encourage discounting power for the energy consumer and paying two cents per kWh of discounted power the energy consumer uses. For a SCC value of 20 CAD per tonne of CO_2, the government provides 0.1% of Ontario's surplus power at each hour to the energy consumer at HOEP. Being able to buy power at this price, the energy consumer replaces 31 diesel forklifts with battery-powered forklifts.

When SCC value is increased to 30 CAD per tonne of CO_2, the optimum value of x increases to 0.6 for the government. However, the optimum value of x for the government remains constant for SCC values of 40, 50, 60, 70, 80, 90, and 100 CAD per tonne of CO_2. When the percentage of discounted surplus power is 0.6% of Ontario's surplus power at each hour, the energy consumer replaces 91 diesel forklifts with battery-powered forklifts and 54 diesel forklifts with fuel cell-powered forklifts. As the value of SCC increases to 110 CAD per tonne of CO_2, the optimum value of x for the government increases to 0.7 and remains the same for SCC values of 110, 120, 130, 140, and 150 CAD per tonne of CO_2. For SCC values of 110, 120, 130, 140, and 150 CAD per tonne of CO_2, the energy consumer is able to purchase 0.7% of Ontario's surplus power at each hour at HOEP, the energy consumer replaces 68 of its diesel forklifts with battery-powered forklifts and 82 of its diesel forklifts with fuel cell-powered forklifts.

Figure 5-4 shows the sensitivity of the number of diesel forklifts, battery-powered forklifts, and fuel cell-powered forklifts the energy consumer operates with respect to different SCC values. As can be seen in Figure 5-4, at lower levels of SCC for the government (which leads to lower levels of subsidized power for the energy consumer), battery-powered forklifts are a more cost-effective option. However, with an increase in the value of x, fuel cell-powered forklifts become a more cost-effective option and the energy consumer will operate more fuel cell-powered forklifts compared to battery-powered forklifts for SCC of higher or equal to 100 CAD per tonne of CO_2.

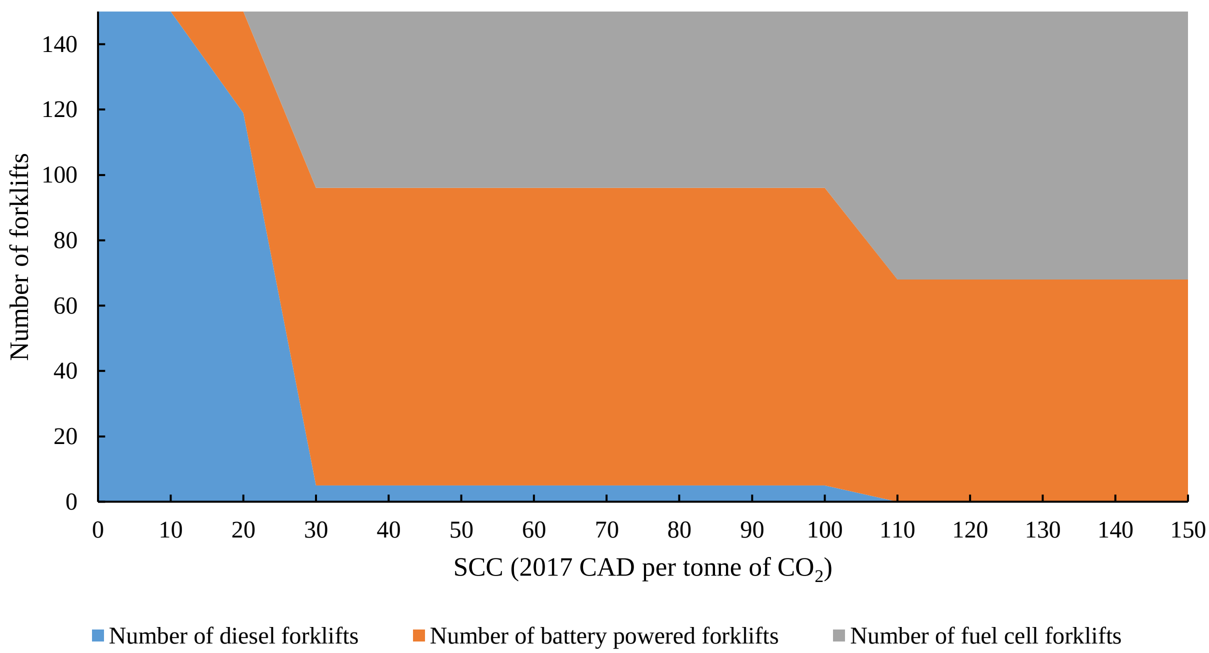


Figure 5-4. The sensitivity of the number of diesel forklifts, battery-powered forklifts, and fuel cell-powered forklifts to different SCC values

Battery-powered forklifts have an advantage over fuel cell-powered forklifts in lower levels of subsidized power due to their lower cost of charging infrastructure. While a battery-powered forklift only needs a battery and a charger to operate, a fuel cell-powered forklift requires electrolyzer, compressor, storage tank, and refueling infrastructure for refueling. Low levels of available subsidized power do not justify the investment in such infrastructure. As a result, the energy consumer starts replacing diesel forklifts with battery-powered forklifts in the beginning.

However, with an increase in the levels of SCC for the government (which leads to higher levels of discounted power for the energy consumer), fuel cell-powered forklifts gain an advantage over battery-powered forklifts. There are two reasons behind this advantage: the lower operating cost of fuel cell-powered forklifts, and the fluctuation in available surplus power in Ontario. As Table 5-2 shows, the operating cost of fuel cell-powered forklifts is lower than that of battery-powered forklifts. Fuel cell-powered forklifts are more expensive to purchase; however, the higher purchase cost is spread over the lifetime of the forklift. The annualized cost of purchasing and operating fuel cell-powered forklifts are, then, lower than battery-powered forklifts if the cost of electricity/hydrogen is not taken into account. The other reason for the preference of fuel cell-powered forklifts over battery-powered forklifts by the energy consumer is the variations in surplus power available in Ontario. Table 4-37 shows the average electricity generation minus average demand in different hours and months in Ontario. As can be seen in Table 4-37, there is an electricity surplus in all hours and months in a year in Ontario. On-peak, mid-peak, and off-peak hours in Ontario are shown in Table 4-9. Figure 4-31 shows surplus electricity in different hours in Ontario in 2017.

As Table 4-37 and Figure 4-31 show, surplus power in July, August, September, and October is significantly lower than other months of the year while surplus power is higher in April and December than other months of the year. The difference in surplus power in different months in Ontario is caused by demand variation and also the variability of intermittent power generation in the province. Fluctuation in surplus power and the assumption in our model that only a specific parentage of surplus power is allocated to energy consumer at each hour, make energy storage a necessary element of the system. In other words, the energy consumer has to invest in some energy storage capacity (whether it is battery or hydrogen) to be able to operate battery-powered and fuel cell-powered forklifts. However, the same amount of surplus power is not available in all months, and also, the electricity price is different in a year. As a result, the energy consumer has to invest in seasonal storage to be able to store power in periods with low electricity prices and use it when power is expensive. Lower cost of hydrogen storage compared to battery storage then gives fuel cell-powered forklifts another advantage over battery-powered forklifts when seasonal storage is needed.

Comparing costs and operating characteristics of battery-powered and fuel cell-powered forklifts shows that when low-cost clean power is available at all times, deploying battery-based technologies is a more cost-effective measure that deploying hydrogen-based technologies. However, when the amount of available low-cost power fluctuates during the year and seasonal storage is needed, hydrogen-based technologies (fuel cell-powered forklifts in this study) become a more cost-effective option compared to battery-powered technologies due to their lower operation and maintenance cost as well as lower hydrogen storage cost compared to battery storage cost. Our analysis shows that replacing diesel forklifts with battery-powered and fuel cell-powered forklifts can be beneficial for both the government and the energy consumer stakeholders in the energy system. Battery-powered forklifts and fuel cell-forklifts were both found to be cost-effective technologies for reducing GHG emissions in Ontario when low-cost surplus power is available for their operation. Replacement of diesel forklifts with battery-powered and fuel cell-powered forklifts is also beneficial for the government as it reduces GHG emissions and subsequently, the social cost of carbon (SCC).

5.1.4 Conclusion

In this study, a game theory model is developed to analyze the interaction of government and an industrial facility (energy consumer) for reducing CO_2 emissions in Ontario by replacing diesel forklifts with battery-powered and fuel cell-powered forklifts. The objective function of the government is defined as the transmission and distribution charge paid for the surplus power made available to energy consumer at discounted price minus avoided social cost of carbon in the case of CO_2 emission reduction by the energy consumer. The objective function of the energy consumer is the annualized cost of operating 150 forklifts. The government's decision variable in our model is the percentage of Ontario's surplus power that is made available to the energy consumer at a discounted price. The government, however, pays two cents per kWh of the energy that is provided to energy consumer at HOEP to cover transmission and distribution costs. The energy consumer (industrial facility) has to operate 150 forklifts (all diesel forklifts in the base case) and has the option to replace them with battery-powered and fuel cell-powered forklifts if it leads to a lower cost for it.

The results of the model developed in this study show that in the equilibrium point, the value of x is equal to zero for SCC equal to or less than 10 CAD per tonne of CO_2. When the value of SCC increases to 20 CAD per tonne of CO_2, the value of x increases to 0.1, meaning the government allocates 0.1% of Ontario's surplus power at each hour to the energy consumer at HOEP and the energy consumer replaces 31 of diesel forklifts with battery-powered forklifts. When SCC value is increased to 30 CAD per tonne of CO_2, the optimum value of x increases to 0.6 and remains the same for SCC values of 40, 50, 60, 70, 80, 90, and 100 CAD per tonne of CO_2. When the percentage of subsidized surplus power is 0.6% at each hour, the energy consumer replaces 91 and 54 of diesel forklifts with battery-powered forklifts and fuel cell-powered forklifts, respectively. As the value of SCC increases to 110 CAD per tonne of CO_2, the optimum value of x for the government increases to 0.7. For SCC values of 110, 120, 130, 140, and 150 CAD per tonne of CO_2, the energy consumer replaces 68 and 82 of diesel forklifts with battery-powered and fuel cell-powered forklifts, respectively.

The analysis in this study also shows that battery-powered forklifts are more cost-effective compared to fuel cell-powered forklifts when lower levels of discounted power are available. However, with an increase in SCC and discounted power available, fuel cell-powered forklifts become more cost-effective. The advantage of fuel cell-powered forklifts over battery-powered forklifts in higher levels of available discounted power is due to lower operation and maintenance cost of fuel cell-forklifts compared to battery-powered forklifts and lower seasonal storage cost of hydrogen compared to batteries. The results of the modeling in this study, however, show that battery-based and hydrogen-based technologies are both effective in reducing GHG emissions in Ontario when surplus renewable power is available. In that sense, battery and hydrogen technologies can act as complementary rather than competing technologies for reducing GHG emissions in Ontario by replacing the use of fossil fuels with clean electricity.

5.2 Assessing the potential of surplus clean power in reducing GHG emissions in the building sector using game theory; a case study of Ontario, Canada

Using the same methodology previously discussed in the section of the thesis, this work assesses the potential of surplus electricity in reducing greenhouse gas (GHG) emissions in the building sector. The assessment is done by modelling the interaction of government and energy consumer using game theory. The government can provide discounted power to energy consumer by covering a fraction of the off-peak price to encourage the replacement of natural gas consumption with electricity. This replacement reduces GHG emissions from the building sector. Energy consumer adopts electricity-based technologies only if it leads to a lower heat and electricity supply cost. Cost-effectiveness of solid oxide fuel cell, air–source heat pump (ASHP), and battery and hydrogen storage are assessed as alternatives to natural gas combined heat and power (CHP) and boiler technologies. The modelling results show that ASHP is the only technology that can compete with natural gas CHP and boiler. ASHP is chosen by the energy consumer when discounts of 4.5 cents per kWh or more for off-peak electricity are available. The analysis also showed that CHP could be completely replaced by grid power at discount value of 4.5 cents per kWh and up. Natural gas boilers continue playing a role in building heating supply even under increased discount for off-peak electricity price.

6 An iterative approach for optimal decarbonization of electricity and heat supply systems

The following section is based on work, by Haghi, E., Qadrdan, M., Wu, J., Jenkins, N., Fowler, M., Raahemifar, K., and is currently under review at the Energy journal. Contribution of authors is detailed in the Statement of Contributions section.

6.1 Introduction

Greenhouse Gas (GHG) emission reduction has become a major worldwide challenge in recent years. Many governments all over the world have introduced programs and set targets to reduce GHG emissions from different energy systems. The United Kingdom (UK) government, for instance, is committed to at least 80% GHG emission reduction in 2050 compared to 1990 levels [189].

6.1.1 Energy consumption and GHG emission from the heating sector

The building sector accounted for 28% of global energy-related CO_2 emissions in 2018 [190]. Domestic buildings with 14% of GHG emissions in 2016 is among the top four contributing sectors to the UK GHG emissions [191]. In 2017, the domestic sector accounted for 28% of final energy consumption in the UK [192] from which two-third was supplied by natural gas, primarily for heating [193]. The significant contribution of the domestic sector to GHG emission and fossil fuel consumption in the UK has made heat electrification an issue of interest in both research and government policies. Electrifying the residential heating systems and replacing natural gas-based heating technologies with electricity-based technologies is recognized as one of the most common strategies suggested for reducing GHG emissions in the residential sector in the UK [194][195][196][197].

6.1.2 Decarbonizing the heat sector

Assessing the potential of using low-carbon technologies in the domestic sector has been analyzed widely in the literature for different case studies in different countries. Modeling tools were developed for investigating the most cost-effective energy efficiency measures and mix of technologies for supplying heat demand for case studies at different scales from a single building to a country.

Literature focused on small scale and single building applications usually aim at assessing technologies (including electricity and heat generation, and storage technologies) and systems that are useful in reducing energy consumption and GHG emission for a building. Lindberg et al. [198], for instance, developed a model for optimal design and operation of technologies for a zero energy building. The developed model in [198], was used to minimize the cost of energy supply for a case study of a school building where different technologies including boilers, combined heat and power (CHP), PV, solar thermal collector, heat storage, air-source heat pump (ASHP), and ground-source heat pump (GSHP) were considered. Using the developed model, authors were able to analyze how policy incentives affect technology selection by end users.

Developing optimization models for finding the most cost-effective combination of technologies and systems for supplying heat and electricity demand at a national or regional scale has also been an area of interest in the literature. Fehrenbach et al. [199], used TIMES (The Integrated MARKAL-EFOM System) modeling framework for system-wide optimization of residential heat and electricity supply in Germany. Authors in [199] considered both heat and electricity supply and demands as well as the transport sector. The objective function considered in [199] is minimizing total discounted system expenditures. Hedegaard and Balyk [200], proposed a mathematical model for finding the optimal investment and operation of energy systems considering residential heat for a case study of the Danish energy system in 2030 with 60% wind power penetration. The proposed model in [200] included heat and electricity supply technologies as well as storage technologies and electricity transmission. The objective of the proposed model in [200] was minimizing the total cost of the system in a year, and it was used to analyze the benefit of the flexible operation of heat pumps. Henning and Palzer [201], proposed a mathematical model to investigate the optimal mix of electricity and heat supply technologies in Germany. Kiviluoma and Meibom [202], used an expansion planning model for minimizing the total cost of the energy system (including investment cost, operation and maintenance cost, and fuel cost of energy conversion technologies) for supplying electricity and heat demand in Finland. The proposed model in [202] was used to investigate the effect of wind power penetration, electric vehicles, and heat storage technologies on power system investments. Jalil-Vega and Hawkes

[203], developed an optimization model for assessing the role of hydrogen in decarbonizing the energy system in the UK from 2015 to 2050. An optimization problem was developed in [203] to find the optimum investment decisions (including size, type, and location of energy conversion technologies) and operation of the system for supplying heat and electricity demand with minimum cost. Zhang et al. [204], developed a mathematical model for minimizing total energy system cost, including investment and operation cost of technologies for supplying heat and electricity demands. Authors in [204], used heat and electricity demands as inputs to the model to find the optimum capacity mix and operation of electricity and heat generation technologies that can be used to supply demand at the lowest cost in a case study of the UK. Heinen et al. [205], proposed an optimization model to find the optimal capacity and dispatch of electricity generation, heat supply, and thermal storage technologies in the Republic of Ireland as their case study. Authors in [205], used a capacity expansion planning methodology with the objection function of minimizing total system cost in their work. Leibowicz et al. [206], developed an optimization model to find the most cost-effective method of reducing GHG emissions in the residential sector for a case study of buildings sector of Austin, Texas, USA. Authors in [206], considered using less carbon-intensive fuels, using more energy-efficient and electrical appliances, and increasing thermal performance of buildings as viable options. Results of the modeling by authors in [206] showed that electrifying end use appliances and decarbonizing electricity supply are the most cost-effective pathway for the case study of Austin, Texas. Ehrlich et al. [207], proposed an optimization model for assessing the potential of power-to-heat for providing flexibility for the German electricity system. Authors in [207], first used a stochastic model to estimate electricity prices in 2020. Electricity prices were then used as input to the optimization model in which heat supply cost for a household was the objective function during 2020.

National and regional heat and electricity supply models, give an understanding of the nation-wide effect of decarbonization policies in both electricity and heat supply sectors and include some supply chain constraints which are applicable at a large scale only. Heat electrification and decarbonization, however, has many aspects that require detailed investigation but are not adequately discussed in the related literature yet. One of these aspects is the increased electricity demand due to heat electrification. Replacing the consumption of natural gas with electricity for heating applications in the residential sector will increase electricity demand. This increase is estimated to be as high as 25% of the daily demand in days of high demand with electrifying only 30% of the heating demand with heat pumps in the UK [208]. Using resistive heating may double daily electricity demand in winter days with high heating requirements [208]. Cooper et al. [209], calculated the effect of heat electrification on the UK's peak electricity demand in different scenarios. Analysis by Cooper et al. [209], also showed that peak demand in the UK might increase up to 100% if the heat pump is used in 80% of UK dwellings. Supplying this increased electricity demand caused by heat electrification requires planning and consideration.

Additionally, the source of electricity used for heating is a crucial point to consider when assessing the potential of heat electrification in reducing GHG emissions. Using wind power for heating homes achieves more GHG emission reduction compared to electrifying heating with power generated in a natural gas power plant. Gas and electricity supply systems also have different variability and uncertainty characteristics. Due to the use of natural gas for heating applications, natural gas demand has a more significant variability compared to energy demand in a year in Great Britain (GB) when compared based on energy values [208]. Electrifying heat will transfer the variability of natural gas demand to electricity demand at least to some extent [208]. As a result, it is crucial to develop electricity supply and demand models that enable us to capture that variability.

6.1.3 Analyzing the UK's decarbonization pathways

As already stated, heat decarbonization in the UK is an area of interest for both academics and policymakers. The interaction of gas and electricity networks in the UK and Great Britain have been investigated in the literature from different aspects. Clegg and Mancarella [210] for instance, developed an integrated gas and electricity model to investigate the effect of heat supply scenarios on the operation and performance gas and electricity networks in the Great Britain. Li and Trutnevyte [211], analyzed the UK electricity sector transition pathways for 2050. The method authors in [211] used was linking the results of a whole energy economy model with a cost-optimization electricity generation planning model. The authors in [211], generated 800 different pathways to include the uncertainties in the electricity generation planning. The results of pathways produced in [211] showed that electricity generation planning under emission reduction limits leads to a higher generation capacity compared to no climate policy scenarios. Quiggin and

Buswell [194], proposed a model for calculating electricity supply deficit in the UK when heat electrification policies are pursued using hourly supply and demand data, The author's modeling presented in [194] showed the importance of hourly modeling of the energy system and the significant effect of heat electrification on electricity supply planning. Clegg and Mancarella [212], developed an integrated gas and electricity network to assess the impact of heat decarbonization on gas and electricity transmission systems in Great Britain. The author's goal in [212] was to develop a model that helps in assessing the infrastructure update requirements under a heat decarbonization policy. Different pathways for 2050 UK's energy system show different shares for heating and electricity generation technologies [213]. At the same time, decarbonizing the electricity sector is recognized as one of the uncertainties in heat decarbonization in the UK [195]. In that sense, developing a framework that helps in identifying the most cost-effective pathways for decarbonizing heat, assessing the effect of policies such as carbon pricing on decarbonization, and analyzing the impact of this decarbonization on the electricity sector is essential.

A literature review of the works done on heat decarbonization at local and regional/national scales in the UK and other countries shows that the proposed models are aimed at minimizing total system cost to determine the size and type of heat and electricity supply technologies. The gap in the literature is considering the role of different stakeholders in the energy system. Research works focusing on multi-stakeholder modeling of heat and electricity sectors to assess the effect of changes made in each of these sectors by rational decision-makers on the other sector are limited. Bauermann et al. [214], presented a coupled model for heat system choice and electricity markets. Authors in [214] used different scenarios distinguished by criteria such as renewable energy penetration and CO_2 emission target to analyze the effect of heating equipment selection by homeowners on electricity supply cost. Technology selection on the supply side and finding the optimum mix of electricity generation technologies was not discussed in [214], and the results presented were focused on heat supply technologies only. In that sense, this study aims at developing a planning model for heat and electricity systems considering their hourly operations. The hourly time resolution of the model helps capture the variation in both supply (renewable energy generation) and demand (heat and electricity). The electricity system problem is solved at the higher level with the objective function of minimizing the cost of electricity supply. Decision variables in the electricity system problem are the size and type of electricity generation technologies. The heat system problem is at the lower level with the objective of minimizing the cost of heat supply. Decision variables of the heat system problem are the share of heating technologies for supplying the heat demand.

An iterative solution algorithm is used in this study for solving the optimization problem. Iterative solutions have been shown to be useful in solving equilibrium problems. Chu et al. [215], for instance, used an iterative method for solving a planning (higher level) and scheduling (lower level) problem. In the method proposed in [215], results from solving the planning (higher level) problem are inserted to the scheduling (lower level) problem. When the scheduling problem is solved and in the case that all constraints are not satisfied, new constraints are generated by the scheduling model and are appended to the higher problem and the higher level problem is solved again. This process continues until all the constraints of the problem are satisfied. The bilevel problem proposed by Bauermann et al. [214], was also solved using an iterative approach to find the system state where electricity price and heat system selection in two levels of the problem converge.

The remainder of this paper is organized as follows: Section 6.2 describes the methodology used in this study and the input data. Section 6.3 presents the results from solving the equilibrium (iterative optimization of heat and electricity systems) and centralized problems in different cases and discusses the results. Section 6.5 concludes the study with a summary of the key findings.

6.2 Methodology

An iterative approach is proposed in this study to investigate the optimal decarbonization pathways for electricity and heat systems while taking into account their interactions and fragmented decision-making processes. In this approach, the planning problems for electricity generation and heat supply are solved iteratively to take into account the feedback between heat and electricity caused by the electricity demand for heating. The iterative approach will help to find the equilibrium state in the problem which shows the optimum mix of electricity generation capacity for the electricity system and optimum size and type of heating system for the heating system when the interaction of systems is taken into account. To compare the results of the iterative approach with the case in which both heat and electricity system problems are solved simultaneously, a centralized formulation of the problem is also developed in this study, and the results of the two different formulations are presented and compared.

6.2.1 Iterative approach for optimizing heat and electricity supply

In the model developed in this study, one optimization problem is planning and operating the electricity system for supplying the electricity demand with the lowest cost. The other optimization problem, on the other hand, is supplying heat demand with the lowest cost. Figure 6-1 shows the structure of the iterative approach used in this study.

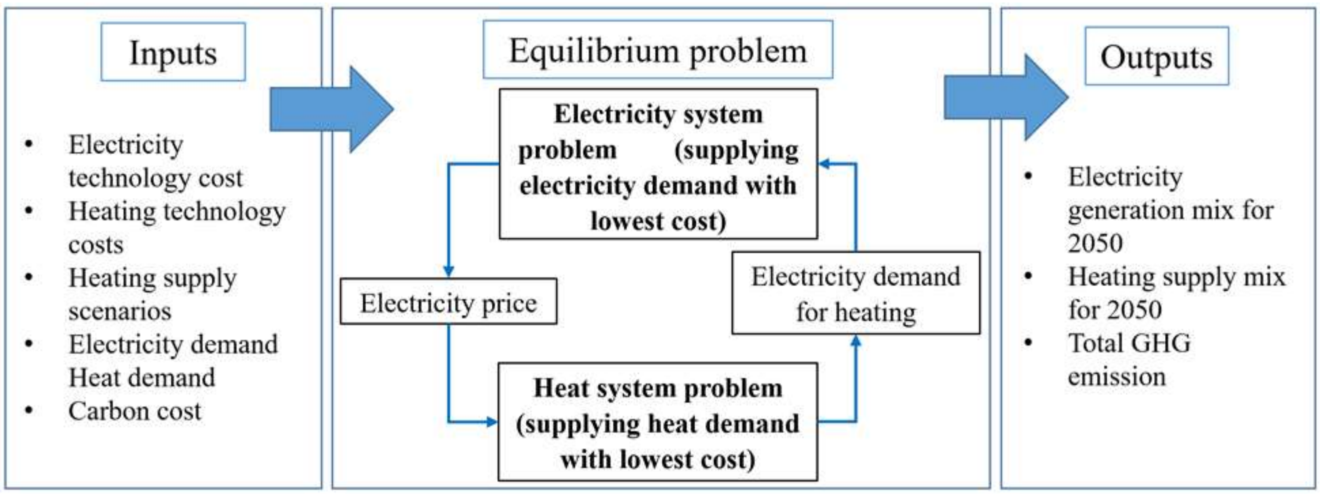


Figure 6-1. Structure of the iterative approach for solving equilibrium problem of heat and electricity supply optimization

As can be seen in Figure 6-1, electricity and heating supply technologies' characteristics, electricity demand, heat demand, and carbon price are inputs to the model. The iterative approach solves the equilibrium problem that concerns optimizing electricity generation and heat supply mix in 2050.

The problem is solved for different carbon cost values. Carbon cost is included in both the levelized cost of energy and levelized cost of heat calculation.

6.2.2 Heat system optimization problem

Heat system problem's objective is minimizing heat supply cost. The heating supply technologies considered in the heat supply problem in this study are:

1. Individual Natural gas boiler

2. Individual biomass boiler
3. Individual Fuel cell (FC) micro-CHP
4. Stirling micro-CHP
5. Community Biomass combined heat and power (CHP)
6. Electric resistive heating
7. Ground source heat pump (GSHP)
8. Air source heat pump (ASHP)

The heat system optimization problem's mathematical formulation is shown in Equation 6-1 to Equation 6-5. Equation 6-1 shows the heat supply problem's objective function.

$$HSPOF = Min\left(\sum_{i=1}^{n} HTCC_i \times HT\_Share_i + \sum_{i=1}^{n} HTO\&MC_i \times HT\_Share_i + \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{i=1}^{n} EIC_{k,i}(t) + \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{i=1}^{n} Input_{k,i}(t) \times EmFactor_k \times Carbon\_Price\right) \tag{6-1}$$

In Equation 6-1, $HSPOF$ is the heat system problem's objective function in £, HT_Share_i is the amount of heating supplied by technology i in unit of heat supply, $HTCC_i$ is the annualized capital cost of heating technology i in £ per unit of heat supply per year, $HTO\&MC_i$ is the operation and maintenance cost of heating technology i in £ per unit of heat supply per year, $EIC_{k,i}(t)$ is fuel input k (electricity, biomass, biogas and natural gas) cost of technology i at hour t in £ , $Input_{k,i}(t)$ is the fuel input k to heating technology i at hour t in kWh of fuel, $EmFactor_k$ is the emission factor of fuel input k in gram (or tonne) of CO_2 per kWh of fuel, and $Carbon\_Price$ is carbon price in £ per tonne CO_2.

Constraints of the heat system problem are shown in Equations 6-2 to 6-5.

$$\sum_{i=1}^{n} HT\_Share_i = 100\% \tag{6-2}$$

$$\sum_{i=1}^{n} Heat\_Output_i(t) \geq Heat\_demand(t) \quad 6\text{-}3$$

$$HT\_Share_i \leq HT\_Share\_Limit_i \quad 6\text{-}4$$

$$EIC_{k,i}(t) = Input_{\,k,i}(t) \times FP_k$$

$$Input_{k,i}(t) = \frac{Heat\_Output_i(t)}{\eta_{heating,i}} \quad 6\text{-}5$$

In Equations 6-2 to 6-5, $Heat\_Output_i(t)$ is the heating output of the heating technology i at hour t in kWh_{th}, $Heat\_demand(t)$ is heat demand at hour t in kWh_{th}, $HT\_Share\_Limit_i$ is heating technology i limit in heating supply share in % of heat supply, FP_k is the price of fuel k in £ per kWh, and $\eta_{heating,i}$ is the heating efficiency (or COP) of heating technology i.

6-2 shows that the sum of the share of all heating technologies should equal 100%. Equation 6-3 shows that the sum of the heat output of all technologies should be enough to supply heat demand at each hour t. 6-4 limits the share of each heating technology i in total heating supply mix to a percentage. Each heating technology has a limited potential for supplying energy consumer's heat demand. In other words, energy consumer cannot supply all its heat demand with a single technology. This constraint is included due to the limited potential of some heating technologies (such as ground source heat pumps), technology supply chain challenges, and availability of some input fuels (such as biomass). Equation 6-5 shows that the input of each heating technology at each hour t equals the heating output of technology at that hour divided by the technology heating efficiency. In the heat system modeling, it is assumed that the electricity output of CHP technologies used for heating supply can only be used for supplying the electricity demand for technologies used in the heating system. In other words, electricity generated by CHP technologies in the heating system may replace electricity purchases from the grid but cannot be sold to the grid.

6.2.3 Electricity system optimization problem

The electricity system problem's objective is minimizing the electricity supply cost. The electricity supply technologies considered in this study are:

1. Solar PV
2. Offshore wind
3. Onshore wind
4. Nuclear
5. Open-cycle gas turbine (OCGT)
6. Combined-cycle gas turbine (CCGT)
7. Coal power with CCS
8. Hydropower
9. Pumped hydro storage

The electricity system problem is shown in Equation 6-6 to 6-15. 6-6 shows the objective function of the energy system problem.

$$ESPOF = Min\left(\sum_{j=1}^{m} TC_j \times (TCC_j + FO\&MC_j) + \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{j=1}^{m} EIC_{k,j}(t) + \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{j=1}^{m} Input_{k,j}(t) \times EmFactor_k \times Carbon\_Price + \sum_{t=1}^{8760}\sum_{j=1}^{m} Electricity\_Output_j(t) \times VO\&MC_j\right) \quad \text{6-6}$$

In Equation 6-6, $ESPOF$ is the electricity system problem's objective function in £, TCC_j is the annualized capital cost of electricity generation technology j in £ per kW, TC_j is the capacity of electricity generation technology j in kW, $FO\&MC_j$ is the fixed operation and maintenance cost of electricity generation technology j in £ per kW of technology capacity, $Electricity\_Output_j(t)$ is the electricity output of technology j at hour t in kWh, $VO\&MC_j$ is the variable operation and maintenance cost of electricity generation technology j in £ per kWh of electricity generated, $EIC_{k,j}$ is fuel input k cost for electricity generation technology j at hour

t in £, and $Input_{k,j}(t)$ is the input k (wind power, solar radiation, natural gas, coal, uranium, water power) to electricity technology j at hour t in kWh of input.

Constraints of the electricity system operator's optimization problem are shown in Equations 6-7 to 6-15.

$$Electricity\_Output_j(t) \leq TC_j \times one\ hour \quad \text{6-7}$$

$$Electricity\ \_Output_j(t) = Input_{k,j}(t) \times \eta_{electrical,j} \quad \text{6-8}$$

$$EIC_{k,j}(t) = Input_{k,j}(t) \times FP_k \quad \text{6-9}$$

$$Capacity_j \leq Build\_rate_j \times 31 \quad \text{6-10}$$

$$Capacity_j \geq Min\_Renewable\_Cap_j \quad \text{6-11}$$

$$Electricity\_Demand(t) \leq \sum_{j=1}^{m} Electricity\_Output_j\ (t) \quad \text{6-12}$$

$$Storage\_level_{Pumped\_Hydro}(t) = \ Electricity\_Input_{Pumped\_Hydro}(t) - Electricity\_Output_{Pumped\_Hydro}(t) + Storage\_level_{Pumped\_Hydro}(t-1) \quad \text{6-13}$$

$$Storage\_level_{Pumped\_Hydro}(t) \geq 0 \quad \text{6-14}$$

$$Storage\_level_{Pumped\_Hydro}(t) \leq Pumped\_Hydro\_StoreCap \quad \text{6-15}$$

In Equations 6-7 to 6-15, $Input_{k,j}(t)$ is the energy carrier input k to electricity generation technology j at hour t in kWh, $\eta_{electrical,j}$ is the electrical efficiency of electricity technology j, FP_k is the price of energy carrier (fuel) k in £ per kWh, $Build\_rate_j$ is the build rate for electricity technology j in kW_e per year, $Min\_Renewable\_Cap_j$ is the minimum capacity for renewable electricity technology j, $\eta_{electrical,j}$ is the efficiency of electrical technology j, and $Electricity\_Demand(t)$ is the electricity demand in hour t in kWh_e.

Constraint shown in Equation 6-8 indicates that electricity generation output of each technology at each hour equals input at each hour multiplied by the efficiency of that technology. Equation 6-9 shows that the electricity output of each technology at each hour cannot exceed the capacity of that technology. There is a build rate constraint on electricity generation technologies. This constraint means only a maximum amount of capacity for a specific type of electricity generation technology can be developed in a year. Equation 6-10 limits the capacity development of each electricity generation technology to a build rate limit. Equation 6-10 indicates that the minimum capacity of offshore wind, onshore wind, and solar power technologies in 2050 cannot be less than their capacity in 2018. This constraint is considered in the model to reflect the government's policy in supporting the development of renewable energy generation capacity. By including this constraint, we are assuming that the capacity of renewable energy generation will not decrease from 2019 to 2050. No such constraint is considered for nuclear, coal, and gas-based technologies. Equation 6-12 shows that the sum of electricity output from all technologies should be enough to supply electricity demand at each hour. 6-13, 6-13, and 6-15 are pumped hydro storage technology constraints. In Equations 6-13, 6-14, and 6-15, $Electricity\_Output_{Pumped\_Hydro}(t)$ and $Electricity\_Input_{Pumped\_Hydro}(t)$ are electricity output and electricity input from pumped hydro technology at hour t in kWh_e and $Pumped\_Hydro\_StoreCap$ is the storage capacity of pumped hydro storage system in kWh_e.

An iterative approach is used in this study to find the equilibrium. Figure 6-2 shows the solution algorithm used in this study.

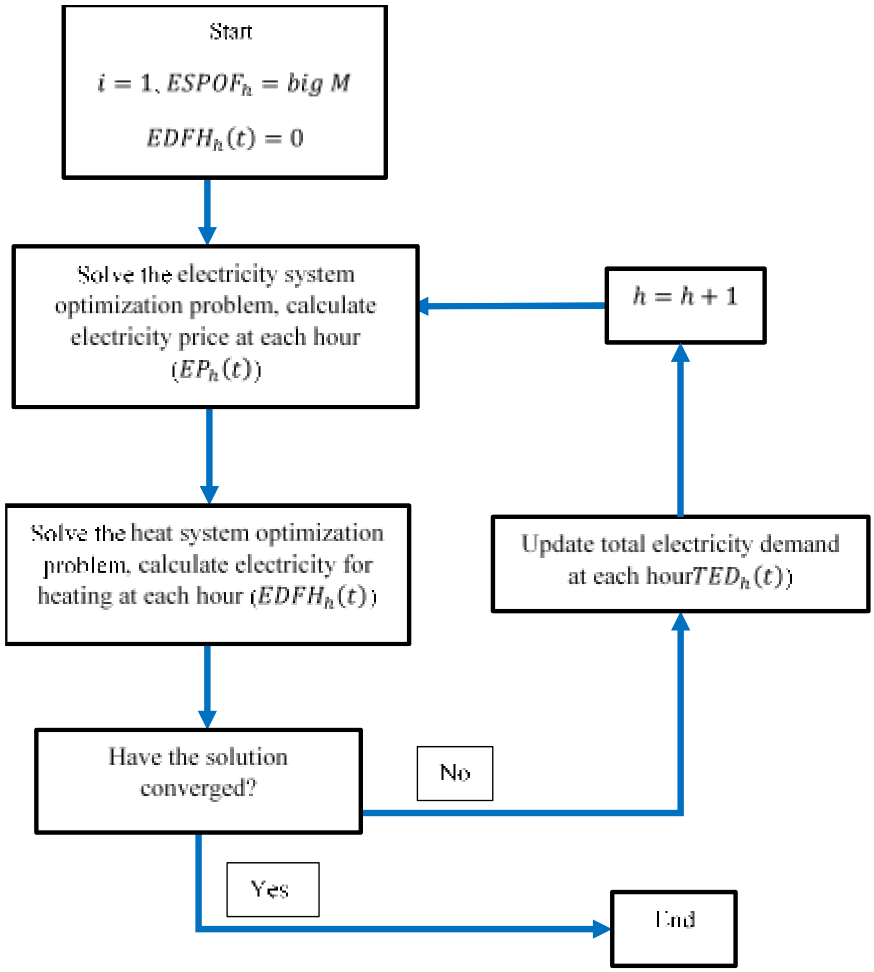


Figure 6-2. Solution algorithm for the equilibrium problem

In Figure 6-2, $ESPOF_h$ is the electricity system problem's objective function at step h in £, $EDFH_h(t)$ is the electricity demand for heating at hour t and step h in kWh$_e$, $EP_h(t)$ is the electricity price at hour t and step h in £ per MWh. Electricity price at each hour is defined as the sum of the levelized cost of electricity (LCOE) at that hour plus transmission and distribution charges. In Figure 6-2, $TED_h(t)$ is the total electricity demand (electricity demand plus electricity demand for heating) at hour t and step h in kWh$_e$.

In the start of the algorithm, $ESPOF_h$ is assumed to have a big positive value ($big\ M$). The electricity supply problem is then solved to find the size and type of electricity generation technologies that are able to supply the electricity demand with the lowest cost. Based on the operation of electricity generation technologies, electricity prices at each hour ($EP_h(t)$) is calculated. Knowing the electricity price at each hour, the heat supply problem is solved in order to find the mix of heating technologies that are able to supply the heat demand with the lowest cost. Electricity demand for heating at each hour t ($EDFH_h(t)$) can then be calculated knowing the share of each heating technology in the heat supply mix. This demand is added to the primary electricity demand and is used as input to the electricity supply problem. The electricity supply problem is then solved again using the new electricity demand and the new objective function ($ESOPOF_{h+1}$) and electricity prices ($EP_{h+1}(t)$) are calculated. Using the electricity new prices, heat supply problem is solved and the new values for electricity demand used for heating ($EDFH_{i+1}(t)$) is found. This process continues until both the electricity system problem and the heat system problem converge to an answer. Convergence happens when electricity and heat supply mix do not change in two consecutive iterations.

The equilibrium problem is solved for different cases differentiated base on the carbon price. Linear Program (LP) in the General Algebraic Modeling System (GAMS) is used for solving the electricity and heat system problems.

6.2.4 Centralized formulation

This section presents the centralized model used for solving the heat and electricity system problem in this study. In the centralized modeling, it is assumed that a single stakeholder makes the decisions about the size and type of electricity generation technologies used for supplying electricity and the share of different heating technologies for supplying heat demand. As a result, the electricity system and the heat system problems are solved at the same time in a centralized formulation of the problem. In the centralized formulation, the objective function is minimizing the cost of supplying heat and electricity, as shown in Equation 6-16.

$$\begin{aligned}
&\text{Centralized problem's objective function} \qquad\qquad \text{6-16}\\
&= Min(\sum_{i=1}^{n} HTCC_i \times HT_Share_i + \sum_{i=1}^{n} HTO\&MC_i \times HT_Share_i \\
&+ \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{i=1}^{n} EIC_{k,i}\,(t) + \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{i=1}^{n} Input_{k,i}(t) \times EmFactor_k \\
&\times Carbon_{Price} + \sum_{j=1}^{m} TC_j \times (TCC_j + FO\&MC_j) \\
&+ \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{j=1}^{m} EC_{k,j}\,(t) + \sum_{t=1}^{8760}\sum_{j=1}^{m} Electricity_Output_j(t) \times VO\&MC_j\,(t) \\
&+ \sum_{t=1}^{8760}\sum_{k=1}^{l}\sum_{j=1}^{m} Input_{k,j}(t) \times EmFactor_k \times Carbon_Price)
\end{aligned}$$

As Equation 6-16 shows, the centralized optimization problem's objective function is the sum of objective functions for heat and electricity system problems in the iterative approach presented before in Equation 6-1 and Equation 6-6, respectively. The constraints of the centralized optimization problem are similar to the constraints for heat and electricity system problems in the iterative approach presented in Equations 6-2 to 6-5 and Equations 6-7 to 6-15.

The optimization problem is solved for different cases differentiated base on the carbon price. Linear Program (LP) in the General Algebraic Modeling System (GAMS) is used for solving the centralized optimization problem.

6.2.5 Input data

The model and formulation described are applied to Great Britain (GB) to show the application of the model in the electricity and heat systems planning. As a result, the data presented in this section is related to the Great Britain's electricity and heat system. However, the presented formulation is general and can be applied to other systems.

Table 6-1 shows the assumed characteristics of heat supply technologies considered in this study.

Table 6-1. Assumed heat supply technologies assumed characteristics (data from [216][217][218])

Heat supply technology	Investment cost (EUR per unit)	Lifetime (years)	Storage/ Electrolyser (EUR per unit)	Fixed O&M cost (EUR per unit year)	Electrical efficiency (%)	Heating efficiency (%)	Maximum share in heat supply (%)
Individual Natural gas boiler	1250	15 [216]	0 [216]	330 [216]	NA[1]	91 [217]	80
Individual biomass boiler	6000 [216]	15 [216]	1300 [216]	320 [216]	NA	87 [217]	10
Individual Fuel cell (FC) micro-CHP	6700 [216]	10 [216]	2700 [216]	330 [216]	45 [217]	45 [217]	90
Stirling micro-CHP	3592	20	0	330	22.5 [217]	63 [217]	20
Community Biomass combined heat and power (CHP)	5350	20	0	330	17 [217]	57 [217]	10
Electric resistive heating	1100 [216]	20 [216]	0 [216]	30 [216]	NA	100	20
GSHP	13400 [216]	15 [216]	0 [216]	110 [216]	NA	COP is assumed to change linearly between 2.5 and 3.8	30

[1] Not applicable

						for temperatures -25 and 18	
ASHP	6700 [216]	15 [216]	0 [216]	110 [216]	NA	COP changes linearly between 1.2 and 3.5 for temperatures -25 and 18 [218]	80

The cost of heating technologies is presented in EUR per unit in Table 6-1. A unit of heating is assumed to be 15 MWh of heating demand [216]. The cost of electricity grid expansion for electric and heat pump heating systems has been considered in the reported costs [216]. Cost of Stirling CHP technology and biomass CHP systems are from comparing the data in [216] and [219]. All heating technology costs are in € 2010 values. An efficiency of 90% is applied to calculate community scale technologies efficiency from individual technologies.

Table 6-2 shows the assumed emission factor and cost of fuels in this study.

Table 6-2. Assumed emission factor and cost of fuels (data from [219][216][220])

Fuel	**Natural gas**	**Biomass**	**Coal**	**Uranium**
Emission factor	143 (g CO_2 per kWh) [219]	37 (g CO_2 per kWh) [219]	Emission from CCS coal plant is reported in Table 6-3.	0
Cost	6.4 (2016 € per GJ) [216]	8.1 (2016 € per GJ) [216]	83,253 (2013 £ per GWh) [220]	8000 (2013 £ per GWh) [220]

Table 6-3 shows the efficiency, operating period, and assumed cost of electricity generation technologies considered in this study. All estimates are in 2014 £ values.

Table 6-3. Assumed efficiency, operating period, and cost of electricity generation technologies (data from [221][222][223][217][224][225][226][227])

	PV	**Offshore wind**	**Onshore wind**	**Nuclear**	**OCGT**	**CCGT**	**Coal CCS**	**Hydropower**	**Pumped hydro storage**
Efficiency (HHV) % [221]	NA	NA	NA	100	34	54	32	100	77
Operating period (years) [221]	25	22	24	60	25	25	25	35	50
Pre-development cost (£ per kW) [221]	60	120	110	240	30	10	70	0	-
Construction cost (£ per kW) [221]	600	2,100	1,200	4,100	300	500	4,200	3300	-
Infrastructure cost (1000 £ per kW) [221]	50	383	165	3.48	37.75	12.58	16	377.4	-
Fixed O&M cost (£ per MW per year) [221]	7,500	45,400	22,400	72,900	5,200	12,200	78,500	18200	11200
Variable O&M cost (£ per MWh)	0	0	0	3 [221]	3 [221]	3 [221]	3 [221]	0	42 [221]
Connection and Use of System charges (£ per MW per year) [221]	1,200	47,000	3,000	500	2,400	3,300	3,800	0	15800
Minimum load	NA	NA	NA	50 [222]	0	0	30 [222]	NA	NA
Ramp rate (% full load per hour)	NA	NA	NA	2	20	8	6	NA	NA

Carbon emission factor (g CO_2 per kWh)	0 [223]	0 [223]	0 [223]	0 [223]	Calculate based on natural gas emission factor and technology efficiency	Calculated based on natural gas emission factor and technology efficiency	115 [226]	0	0
Build rate	2.3 GW per year based on data from [217]	2 GW per year based on data from [217]	1 GW per year based on data from [217]	1 GW per year based on data from [217]	Assumed to be similar to CCGT	5 GW per year [224]	Assumed to be similar to CCGT	Max capacity of 2.1 GW by 2050 [217], the current capacity of 1.9 GW [225]is preserved	No additional capacity, the current capacity of 2.7 GW [225] is preserved
Minimum developed capacity	13.3 GW [227]	9.4 [227]	12.6 [227]	0	0	0	0	0	0

Offshore and onshore wind power potential is calculated based on the data available in [225] and [228]. Solar power potential is calculated based on the data available in [229]. Hydropower potential is calculated from the data available in [225].

Heat demand in Great Britain in 2050 is assumed similar to the heat demand in 2010. In this study, we are assuming that the increase in heat demand due to population increase is compensated with better home insulation and heat demand remains constant. Similarly, we are assuming that heat demand in 2050 is similar to 2017 in Great Britain (not including electricity demand for heating). Electricity demand considered in this study is based on the 2017 electricity data available in [230]. Electricity transmission and distribution cost is assumed to be 4 pence per kWh based on the data available in [231]. The storage capacity of pumped hydro storage systems is assumed to be 30 GWh. In this study, it is also assumed that all current electricity generation capacity except for hydro and pumped hydro systems will be retired by 2050. As a result, only operation and maintenance cost for current hydro and pumped hydro capacity is considered in the model while capital cost as well as operation and maintenance cost is considered for new hydro and other electricity generation technologies. All values reported in the results section are in 2014 £ values.

6.3 Results and discussion

In this section, the results of the equilibrium and centralized approaches are presented and compared.

6.3.1 Results of the bilevel model

Cases in the bilevel model are differentiated based on the carbon price input used. The cases investigated in this study are:

1. Case 1; equilibrium, carbon price of £18 per tonne CO_2
2. Case 2; equilibrium, carbon price of £30 per tonne CO_2
3. Case 3; equilibrium, carbon price of £70 per tonne CO_2
4. Case 4; equilibrium, carbon price of £100 per tonne CO_2
5. Case 5; equilibrium, carbon price of £150 per tonne CO_2
6. Case 6; equilibrium, carbon price of £200 per tonne CO_2
7. Case 7; equilibrium, carbon price of £300 per tonne CO_2

Figure 6-3 shows the electricity generation capacity in different cases of the equilibrium problem.

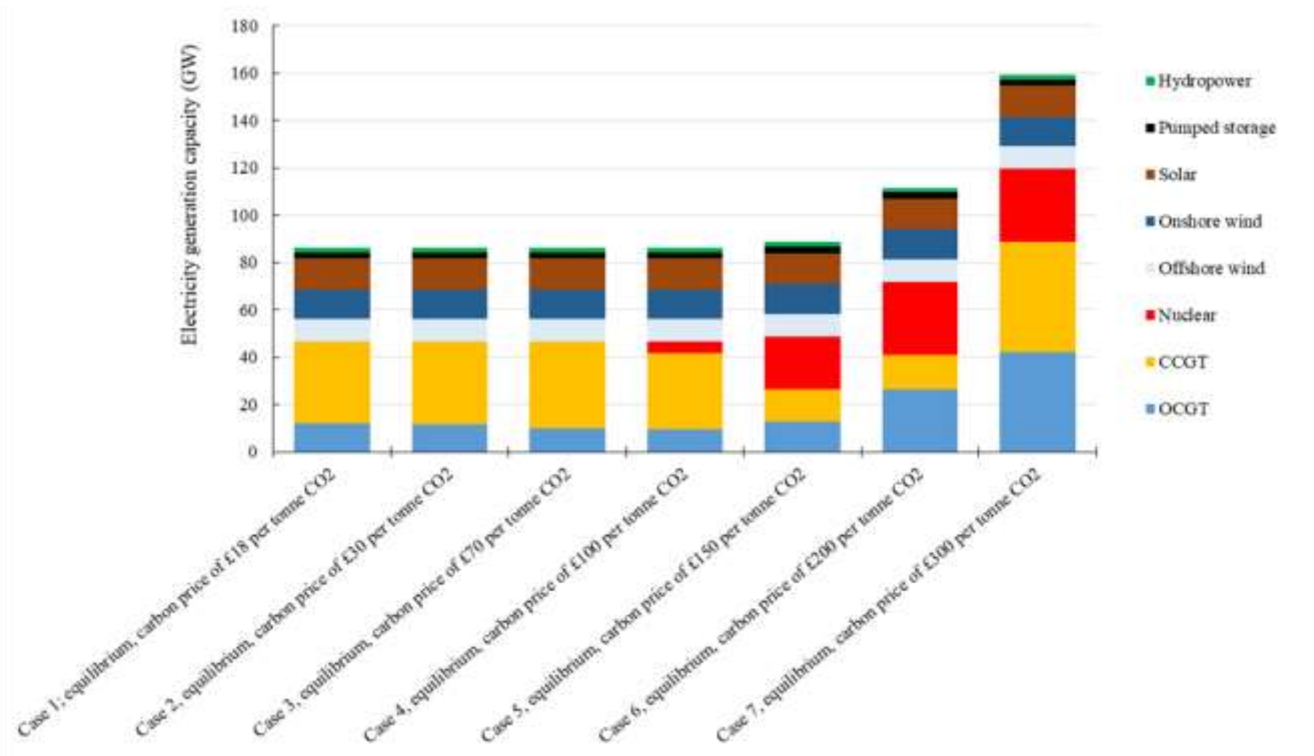


Figure 6-3. Electricity generation capacity in different cases of the equilibrium model

As can be seen in Figure 6-3, CCGT has the highest generation capacity in cases with carbon prices of £18, £30, £70, and £100 per tonne CO_2. Nuclear only becomes the technology with dominant generation capacity in carbon price of £150 per tonne CO_2 which is the reason for the drop in emission reduction in electricity supply for carbon price of £150 per tonne CO_2 seen in Figure 6-7. Figure 6-3 also shows that the capacity of renewable generation technologies (solar, offshore wind, onshore wind, and hydropower) is constant in all cases. The results of our modeling show that increasing carbon prices will lead to the replacement of gas-based technologies with nuclear power and not renewable power generation.

Figure 6-4 shows the share of technologies in supplying electricity demand in different cases of the equilibrium model. As can be seen in Figure 6-4, nuclear power supplies about 60% of electricity demand in Case 5; equilibrium, carbon price of £150 per tonne CO_2 and about 70% of the demand in Case 6; equilibrium, carbon price of £200 per tonne CO_2. Figure 6-4 shows that although the share of CCGT in electricity supply is constantly decreasing with carbon price increase from £70 to £200 per tonne CO_2, the share of CCGT in supplying electricity increases when carbon price increases from £200 to £300 per tonne CO_2. In other words, an increase in carbon price has caused an increase in GHG emissions from the electricity system as can also be seen in Figure 6-7.

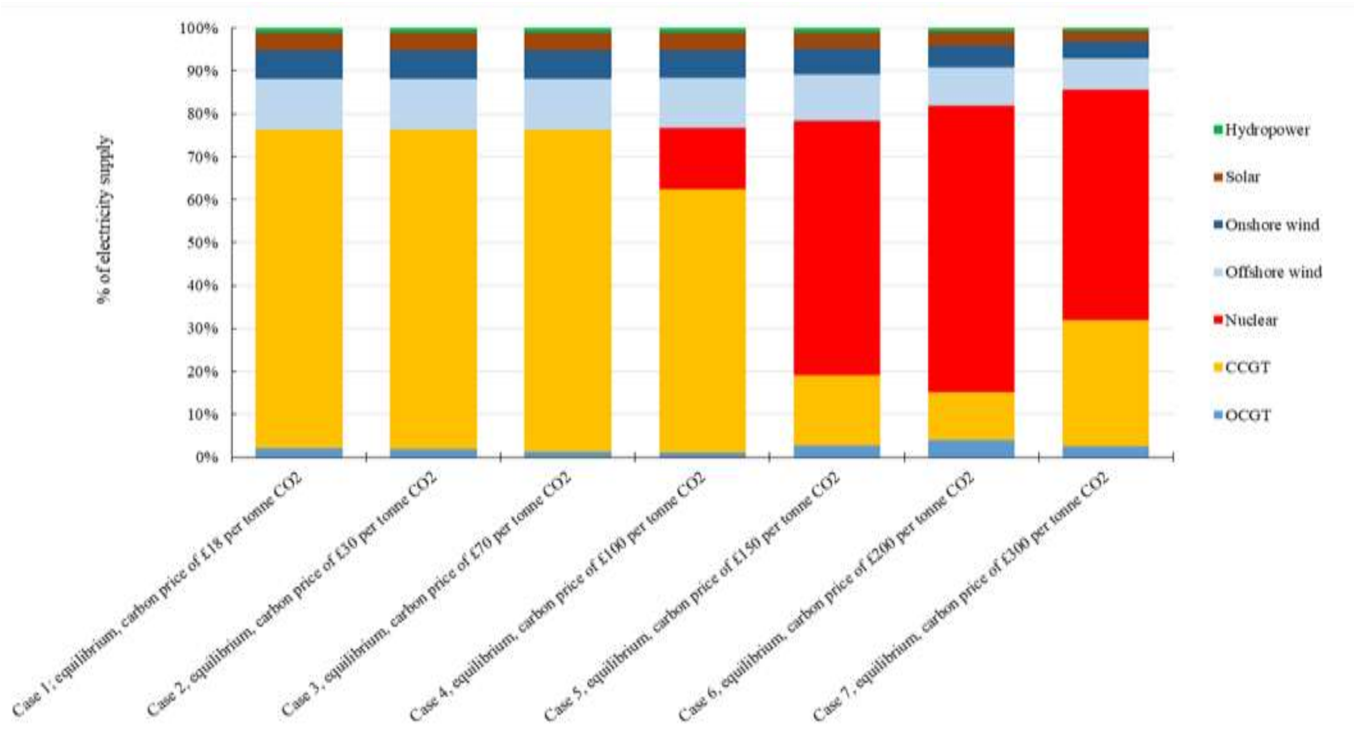


Figure 6-4. The share of technologies in supplying electricity demand in different cases of the equilibrium model

Figure 6-5 shows the load duration curve for Case 5; equilibrium, carbon price of £150 per tonne CO_2, Case 6; equilibrium, carbon price of £200 per tonne CO_2, and Case 7; equilibrium, carbon price of £300 per tonne CO_2. As can be seen in Figure 6-5, peak load in Case 7; equilibrium, carbon price of £300 per tonne CO_2 increases more than 45 GW compared to Case 6; equilibrium, carbon price of £200 per tonne CO_2. This increase in peak demand caused by heat system electrification is the reason behind the increase in power generation capacity of both CCGT and OCGT technologies in Case 7; equilibrium, carbon price of £300 per tonne CO_2 seen in Figure 6-3. The increased electricity demand in Case 6; equilibrium, carbon price of £200 per tonne CO_2 compared to Case 5; equilibrium, carbon price of £150 per tonne CO_2, however, can be supplied by nuclear power (nuclear power has not reached its maximum capacity in Case 5) and OCGT. As a result, there is no need for the development of CCGT capacity.

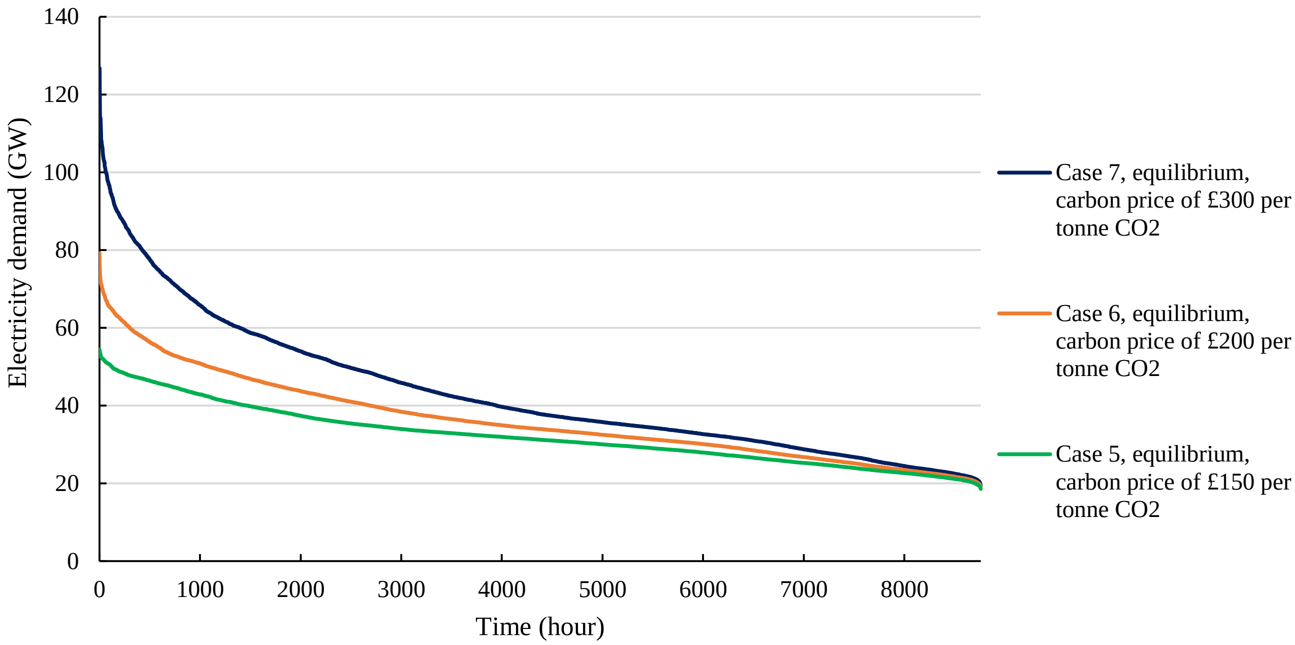


Figure 6-5. Load duration curve for Case 5, Case 6, and Case 7

Figure 6-6 shows the share of technologies in supplying heat demand in different cases of the equilibrium problem.

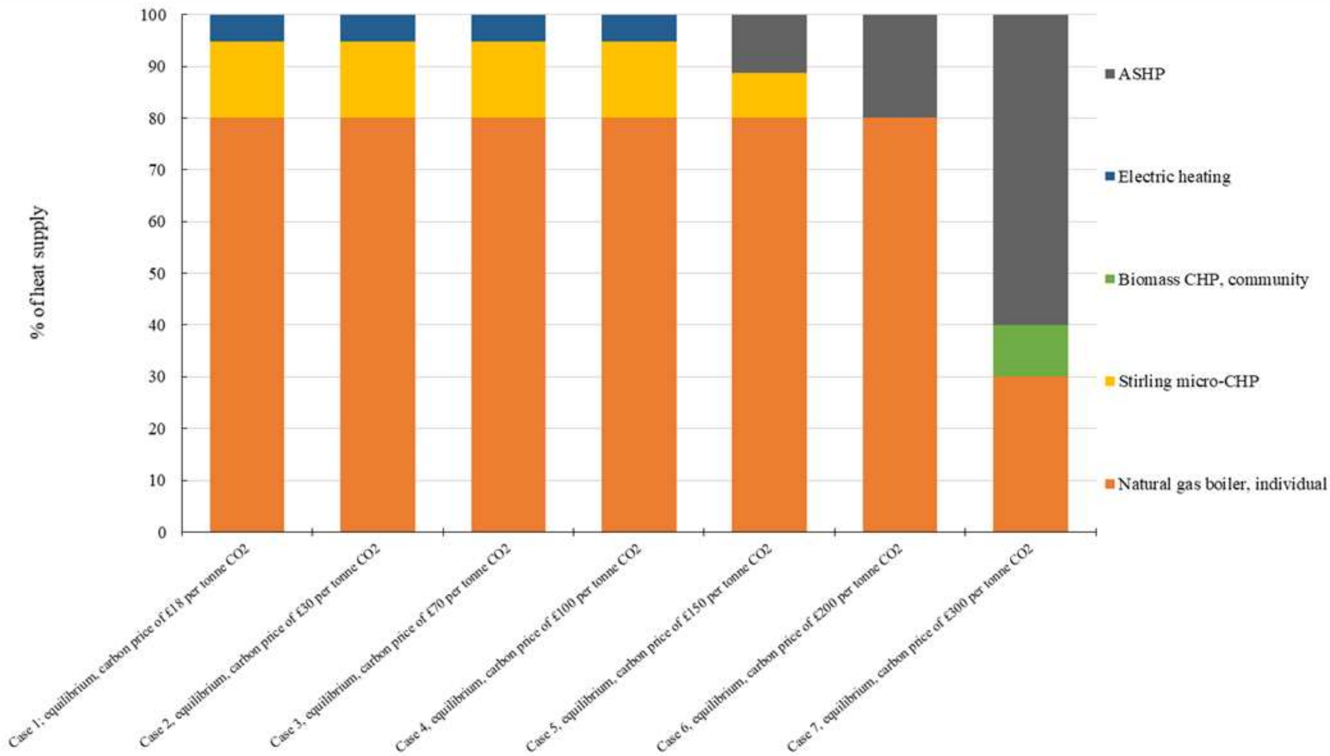


Figure 6-6. The share of technologies in supplying heat demand in different cases of the equilibrium model

As can be seen in Figure 6-6, natural gas boiler is the dominant heating supply technology in all cases except in Case 7; equilibrium, carbon price of £300 per tonne CO_2. In other words, regardless of how much carbon price increases from £18 to £200 per tonne CO_2, natural gas boiler supplies 80% of the heating demand. However, when carbon price increases to £300 per tonne CO_2, it is more cost-effective to use electricity-based technologies such as air-source heat pump to supply electricity to avoid paying high carbon prices. In Case 7; equilibrium, carbon price of £300 per tonne CO_2, ASHP is at its share limit (60%), and the other 40% of the heat is supplied by biomass CHP (10%) and natural gas boiler (30%).

The electrification of heating supply in Case 7; equilibrium, carbon price of £300 per tonne CO_2 is the reason for the increase in CCGT capacity and share in electricity supply shown in Figure 6-3 and Figure 6-4. Although in carbon price of £300 per tonne CO_2, nuclear power is more cost-effective than CCGT, nuclear has reached its build rate limit (31 GW), and the vast electrification in heating supply has to be supplied by electricity generation capacity. While renewables are not able to supply the needed power for heat electrification due to their intermittency, developing CCGT (and even OCGT) capacity is the only way to supply the increased electricity demand.

Figure 6-7 shows GHG emissions from heat and electricity supply in different cases of the equilibrium problem.

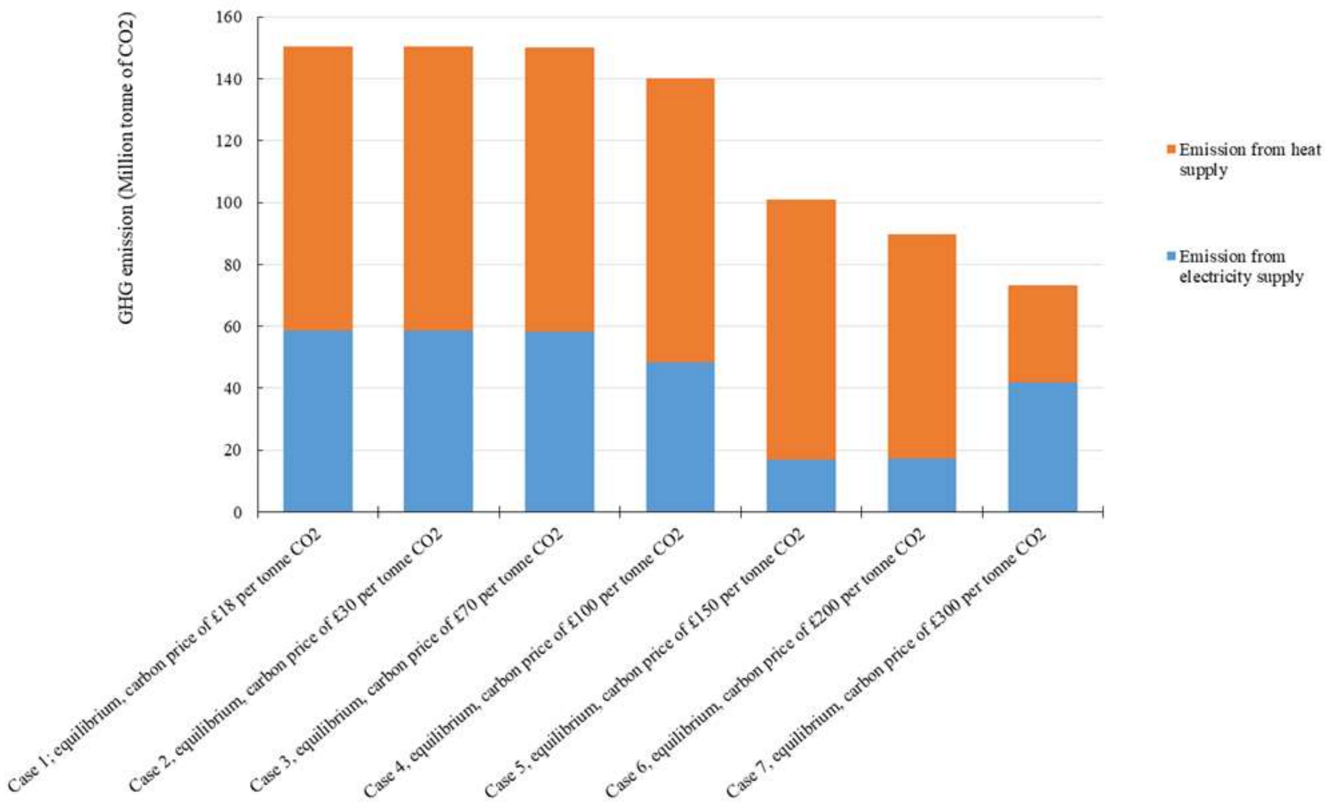


Figure 6-7. Emission from heat and electricity supply in different cases of the equilibrium model

As can be seen in Figure 6-7, increasing the carbon price from £18 to £30 and even £70 per tonne CO_2, does not affect the GHG emission from either of the heat and electricity systems. In other words, the carbon prices of up to £70 per tonne CO_2 are not high enough to make low-carbon technologies more cost effective than fossil fuel-based technologies in heat and electricity systems. When carbon price increases to £100 per tonne CO_2, however, emission from the electricity system decreases. Increase in carbon price to £150 and £200 per tonne CO_2, leads to more decrease in electricity system emissions, which results in an overall emission reduction. On the other hand, emission from the heat system is constant for carbon prices of £100 per tonne CO_2 and below. Emission reduction from the heat system for higher carbon prices is also less significant than emission reduction from electricity supply. Only a carbon price increase from £200 to £300 per tonne CO_2 can result in a sharp emission reduction from the heat system.

Figure 6-8 shows the total GHG emission with respect to the levelized cost of electricity (LCOE) and the levelized cost of heat (LCOH) in different cases of the equilibrium formulation.

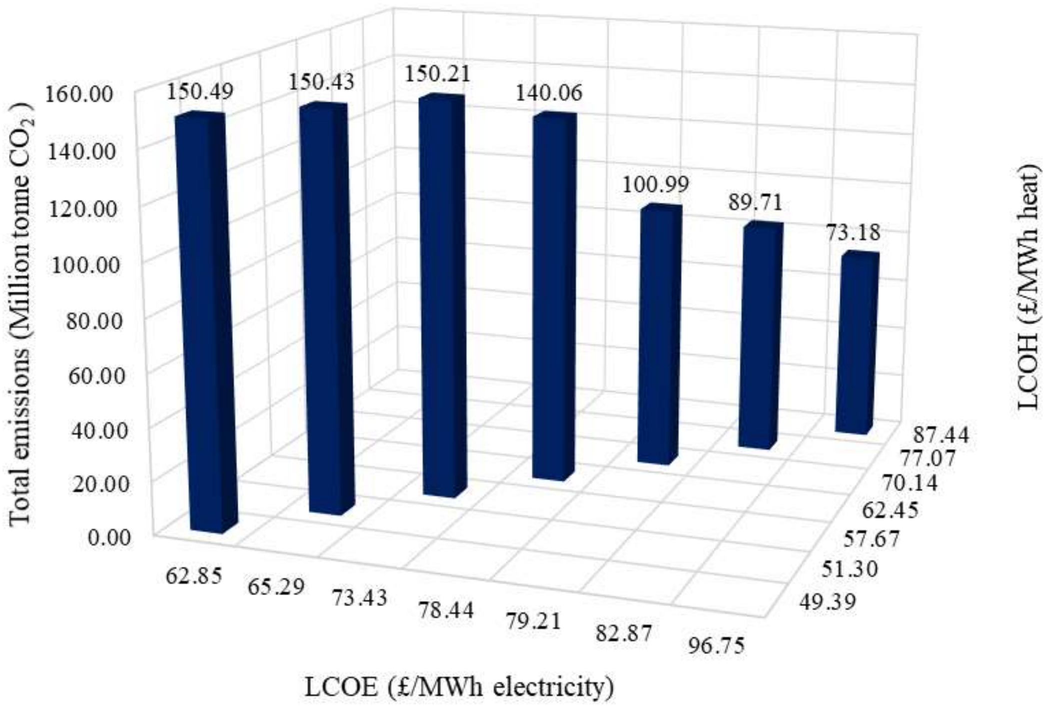


Figure 6-8. Total GHG emission with respect to LCOE and LCOH in different cases of the equilibrium model

As can be seen in Figure 6-8, increasing the carbon price from £18 to £30 and then £70 per tonne CO_2, does not affect overall (sum of electricity and heat) emission while it leads to an increase in the levelized cost of electricity and levelized cost of heat. When carbon price increase from £18 to £30 and then £70 per tonne CO_2, CCGT and natural gas boiler remain the most cost-effective technologies in the electricity and heat systems, respectively. As a result, a higher carbon price only increases electricity and heat levelized cost while it does not lead to any change in the technology mix.

Figure 6-8, however, shows that while carbon price increase from £18 to £30 and £70 per tonne CO_2 does not affect GHG emissions, increasing carbon prices to £100, £150, £200, and £300 per tonne CO_2, leads to a continuous drop in GHG emissions. A major drop in GHG emission (150.21 to 100.99 million tonne CO_2) happens when carbon price increases from £100 to £150 per tonne CO_2 due to the replacement of CCGT with nuclear in electricity system and to a lesser degree, replacement of Stirling micro-CHP with air-source heat pump in heat system as can be seen in Figure 6-4 and Figure 6-6.

In the case of £300 per tonne CO_2 carbon price, emission from electricity supply increases while the significant electrification in heat supply (and consequently emission decrease) will lead to a decrease in total GHG emission as can also be seen in Figure 6-8.

The important point to notice here is that if a GHG emission reduction policy is aiming at heat electrification to decrease GHG emissions, it should assure that there is enough low carbon reliable power generation capacity available to supply the increased electricity demand caused by heat electrification. If that is not the case, a heat electrification policy leads to a GHG emission increase in the electricity system as was seen in our modeling.

6.3.2 Results of the centralized model

In this section, the results of solving the centralized optimization problem in different cases are presented. Cases are differentiated based on the carbon price input used. The cases investigated in this study are:

1. Case 8; centralized, carbon price of £18 per tonne CO_2
2. Case 9; centralized, carbon price of £30 per tonne CO_2
3. Case 10; centralized, carbon price of £70 per tonne CO_2
4. Case 11; centralized, carbon price of £100 per tonne CO_2
5. Case 12; centralized, carbon price of £150 per tonne CO_2
6. Case 13; centralized, carbon price of £200 per tonne CO_2
7. Case 14; centralized, carbon price of £300 per tonne CO2

Figure 6-9 shows the electricity generation capacity in different cases of the centralized formulation. As can be seen in Figure 6-9, the total electricity generation capacity has remained almost constant in all carbon prices. The differences between cases with increasing carbon prices is the replacement of CCGT capacity with nuclear capacity. The electricity generation capacity has remained constant as no significant electrification has happened in the heat system. In the equilibrium problem, however, electricity generation capacity increases in carbon prices of £200 and £300 per tonne CO_2 compared to cases with lower carbon prices to respond to heat electrification.

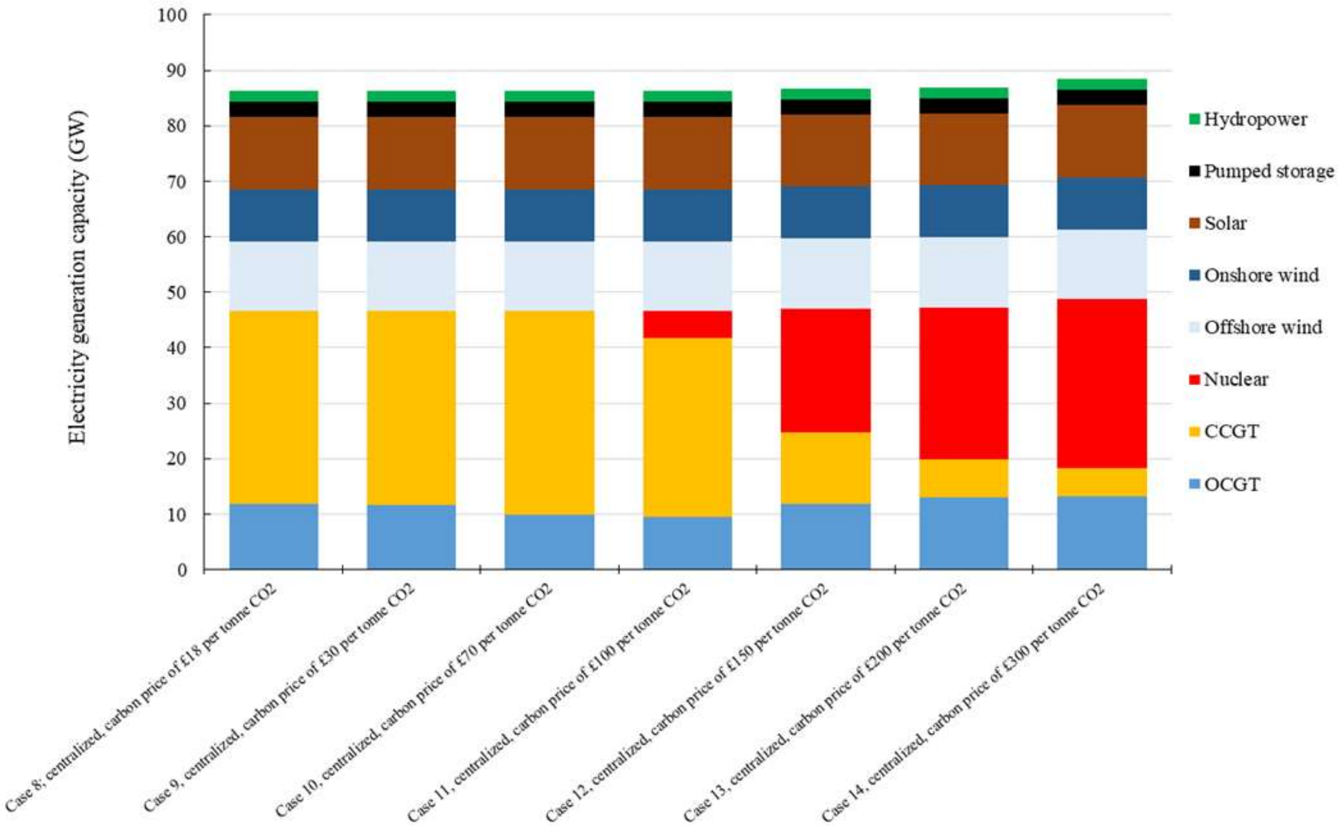


Figure 6-9. Electricity generation capacity in different cases of the centralized model

Figure 6-10 shows the share of technologies in supplying electricity demand in different cases of the centralized formulation.

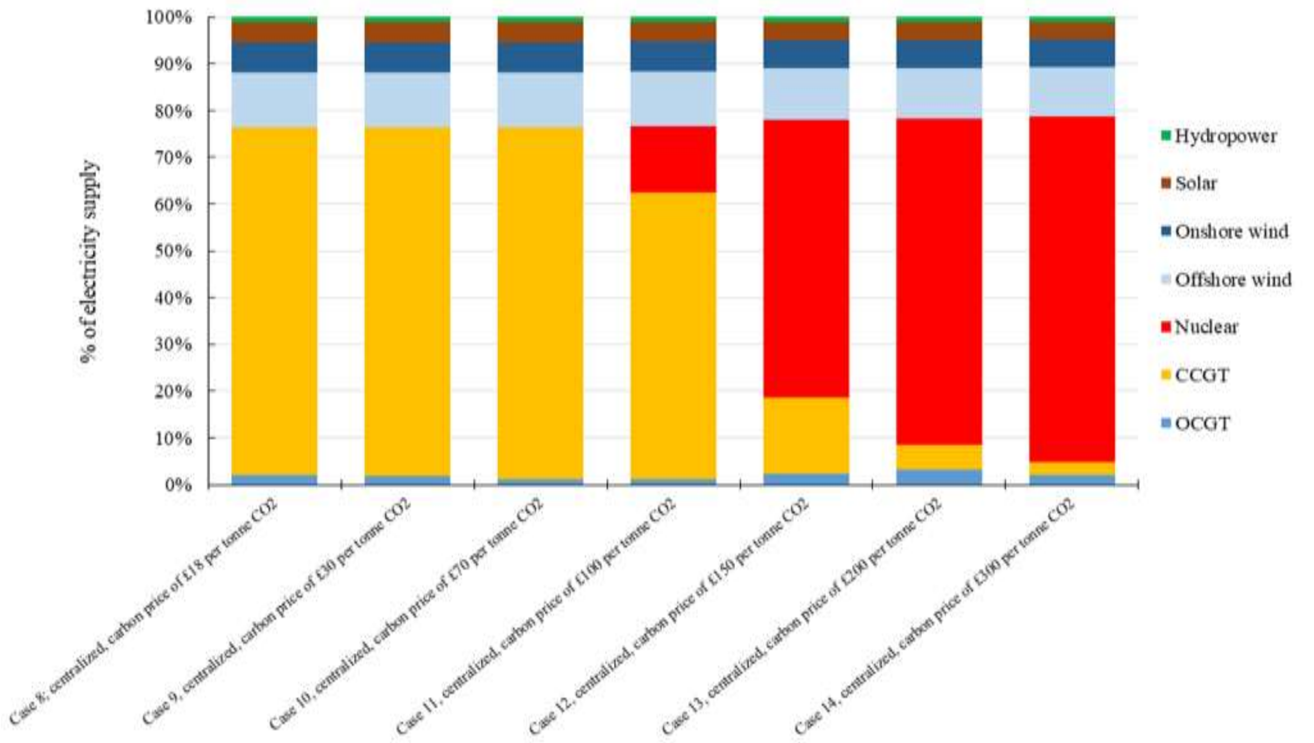


Figure 6-10. The share of technologies in supplying electricity demand in different cases of the centralized model

As can be seen in Figure 6-10, nuclear starts to have a share in electricity supply when carbon prices is £100 per tonne CO_2 and is the dominant electricity supply technology for carbon prices of £150, £200, and £300 per tonne CO_2. Unlike the equilibrium formulation, CCGT has a marginal role in supplying electricity when carbon price is as high as £300 per tonne CO_2 (see Figure 6-4). Figure 6-11 shows the share of technologies in supplying heat demand in different cases of the centralized formulation.

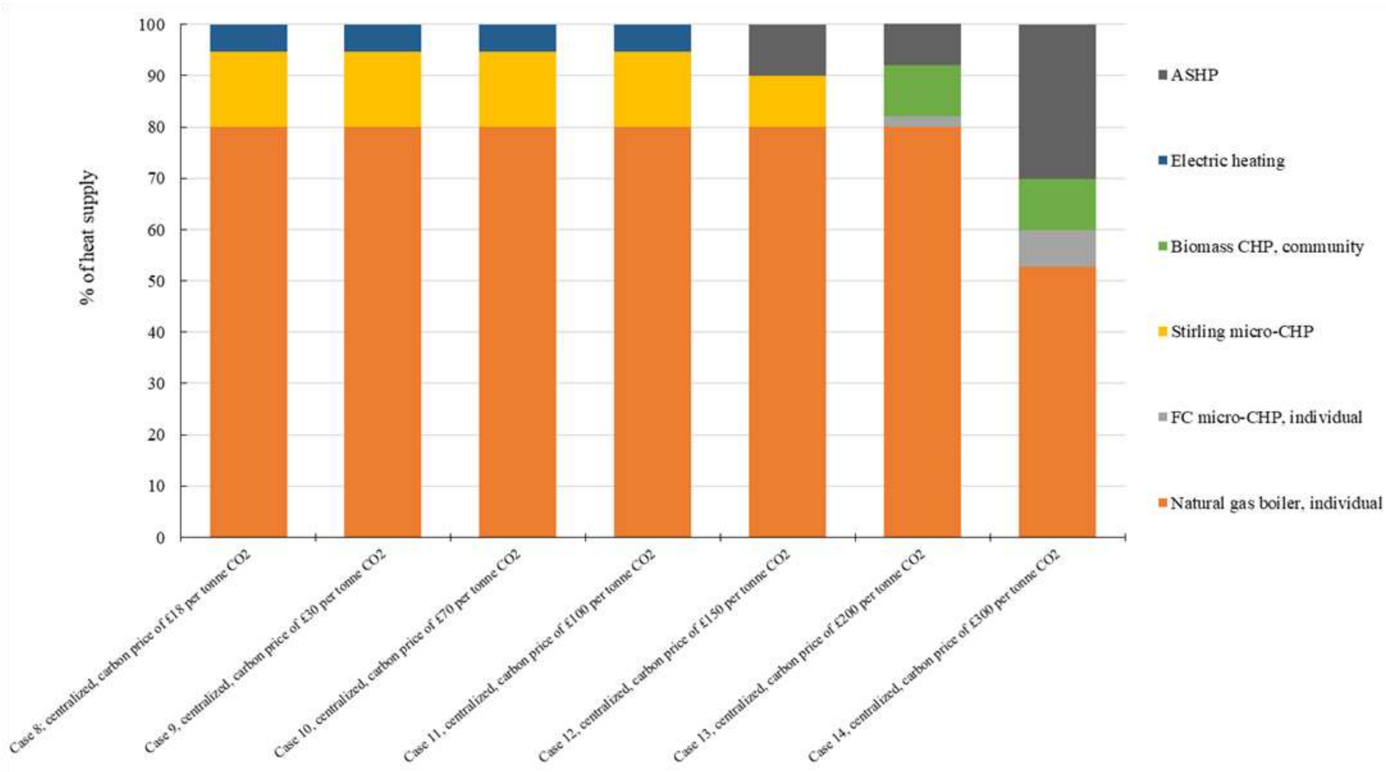


Figure 6-11. The share of technologies in supplying heat demand in different cases of the centralized model

As can be seen in Figure 6-11, natural gas boiler supplies 80% of the heat demand in cases with carbon prices of £18, £30, £70, £100, £150, and £200 per tonne CO_2. Even when carbon price increases to £300 per tonne CO_2, natural gas boiler supplies about 53% of the heat demand.

Figure 6-12 shows the emission from heat and electricity supply in different cases of the centralized formulation.

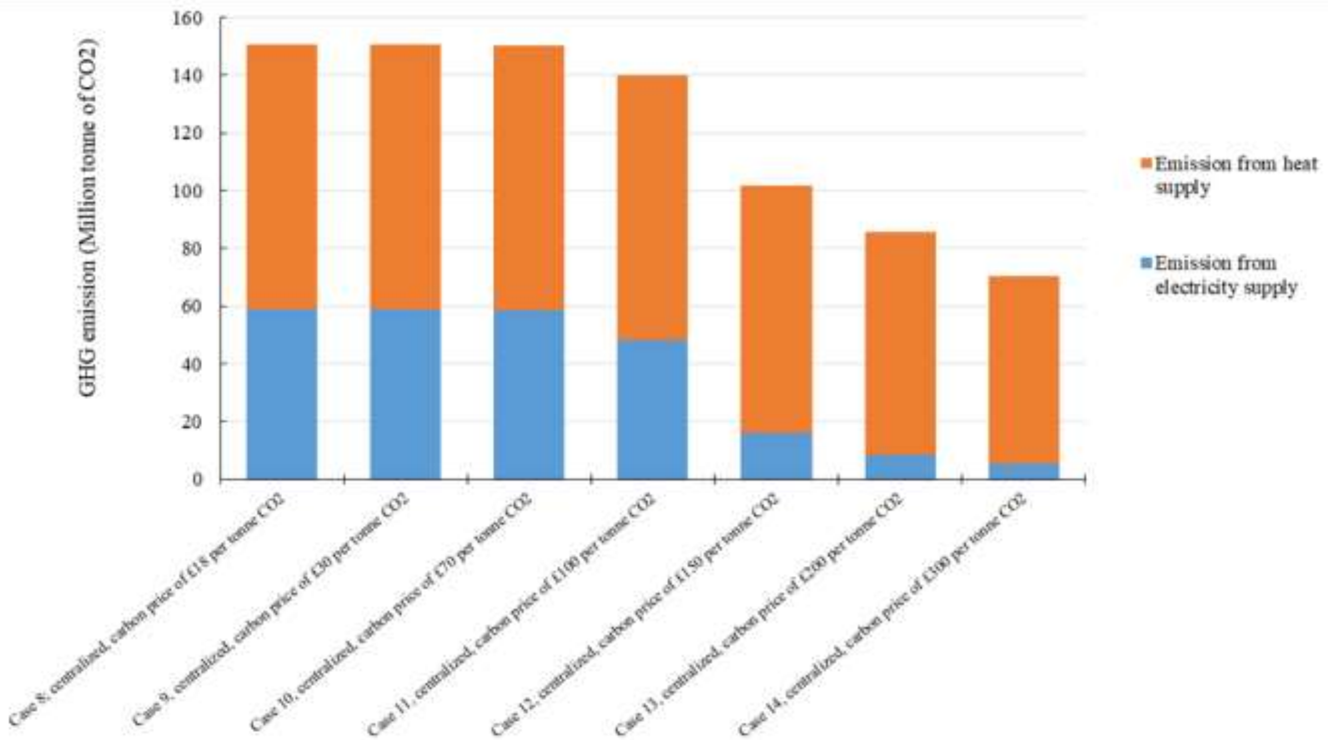


Figure 6-12. Emission from heat and electricity supply in different cases of the centralized model

Similar to the results of the equilibrium model, GHG emission remains constant when carbon price increases from £18 to £30, and £70 per tonne CO_2. A higher carbon price, however, leads to emission reduction from heat and electricity supply. The total amount of GHG emission in each case of centralized modeling is similar to what is found in the equilibrium problem. However, it is worth noting that while in Case 7; equilibrium, carbon price of £300 per tonne CO_2 total emission is split between the electricity and heat systems (57% and 43%, respectively), in Case 14; centralized, carbon price of £300 per tonne CO_2, total emission is almost entirely from the heat supply (93%).

6.4 Discussion

Imposing a carbon price that is effective in reducing GHG emissions in all systems of an energy system is a challenge for policymakers and governments all over the world. The results of our study show that increasing the carbon price from £18 to £30 and then £70 per tonne CO_2 does not reduce emissions from electricity and heat systems. Increasing carbon price to £100 per tonne

CO_2, however, would lead to a 7% GHG emission decrease. More significant GHG emission reductions could be observed when carbon prices are £150, £200, and £300 per tonne CO_2 with a GHG emission reduction of 33%, 40%, and 51% compared to the case with carbon price of £18 per tonne CO_2. These values can be seen in Figure 6-8.

Increase in carbon prices leads to a replacement of CCGT baseload generation with nuclear power generation as can be seen in Figure 6-3 and Figure 6-4. The share of renewable energy generation systems, however, does not change with carbon prices as high as £200 and £300 per tonne CO_2 considering their intermittency and high capital cost. Offshore wind power capacity will be selected by the model in carbon prices of over £200 per tonne CO_2 if a 20% reduction in capital cost is achieved. It should be noted that heat electrification will create a need for the development of baseload generation capacity. If the development of low-emission or emission-free generation capacity is limited (by nuclear build rate, for instance), gas-based electricity generation technologies have to be developed to supply the increased electricity demand.

Natural gas boiler is the most cost-effective heating supply technology for carbon prices of £200 per tonne CO_2 and lower, as can be seen in Figure 6-6. Low capital cost and high efficiency of natural gas boiler give it an advantage over other heating supply technologies. The reason for the preference of natural gas boilers over other heating technologies even in high carbon prices is the effect of a system-wide carbon price mechanism on electricity prices. If carbon prices are imposed on carbon emission in all systems of an energy system, electricity generated and supplied to the heating system will also have a higher price. As a result, electricity-based heating technologies such as heat pumps may not still be able to compete with the natural gas boiler which does not need electricity to supply heating demand. As a result, a system-wide carbon price may not work in favor of low-emission heating supply technologies. However, the results of our modeling show that with a carbon price of £300 per tonne CO_2 heating supply moves toward electrification. With a carbon price of £300 per tonne CO_2, the share of natural gas boiler drops from 80% to 30% compared to the case with a carbon price of £200 per tonne CO_2 and air-source heat pumps become the dominant heating supply technology supplying 60% of the heat demand as shown in Figure 6-6.

Comparing the results from equilibrium and centralized formulation show that these two approaches may have the same results for the optimum mix of heat and electricity supply technologies in some cases. The cases with similar results for equilibrium and centralized modeling are cases where there are dominant fossil fuel-based technologies in the system which have lower electricity and heat supply costs with a significant margin compared to other technologies. In those cases, the equilibrium problem is solved in one iteration where fossil fuel-based technologies are chosen for both heat and electricity systems. When zero or marginal electricity-based technologies are selected in the heating system, there is no or marginal need for capacity development in the electricity system. However, when carbon prices increase to a level where low or zero-emission technologies in both electricity and heat systems become cost-effective and can compete with fossil fuel-based technologies, equilibrium and centralized modeling approaches lead to different results.

The results of the equilibrium model show that both electricity supply and heat supply mix move toward low emission technology mixes with increasing carbon prices. In other words, both electricity and heat supply mixes tend to have lower emissions as the heating and electricity supply technologies are not competitors. However, a lower-emission mix in the heat supply mix means more electricity-based technologies (such as heat pumps) are used in supplying heat. As a result, the electricity demand from heat supply increases which leads to the development of gas-based electricity generation technologies as nuclear power has reached its maximum capacity and renewable technologies cannot supply the reliable power needed. In the centralized problem, the cost of heat and electricity supply are summed up in one single objective function. As a result, the cost of electricity and heat supply compete. If a higher heat supply cost leads to a significantly lower cost in the electricity system, the model will choose the combination of technologies with low electricity supply cost and high heat supply cost which minimizes the overall cost of the system.

Table 6-4 compares electricity generation capacity, heat supply mix, and CO_2 emission for equilibrium and centralized formulation with £300 per tonne CO_2 carbon price.

Table 6-4. Electricity generation capacity, heat supply mix, and CO_2 emission for equilibrium and centralized formulation with a carbon price of £ 300 per tonne CO_2

Parameter	**equilibrium model**	**Centralized model**
Nuclear capacity	31 GW	30.5 GW
CCGT capacity	46.6 GW	5.1 GW
OCGT capacity	42 GW	13.2 GW

Renewable (hydro, offshore wind, onshore wind, solar) capacity	36.9 GW	36.9 GW
Emission from the electricity system	41.9 Mt CO_2	5.2 Mt CO_2
Air-source heat pump share in heating supply	60 %	30.1 %
Natural gas boiler share in heating supply	30%	52.7 %
Biomass CHP share in heating supply	10%	10 %
FC micro-CHP share in heating supply	0 %	7.2 %
Emission from the heat system	31.3 Mt CO_2	65.1 Mt CO_2
Total emission	73.2 Mt CO_2	70.2 Mt CO_2

As can be seen in Table 6-4, total emission from solving the model with equilibrium and centralized formulation has close values (73.2 and 70.2 Mt CO_2, respectively). In the equilibrium formulation, the share of electricity and heating systems in total emission is 57% and 43%, respectively. In the centralized formulation, however, the share of electricity and heating systems in total emission is 7% and 93%, respectively. Table 6-4 also shows that the electricity generation capacity developed in the equilibrium formulation is higher than the centralized formulation to supply the electricity demand created due to heat electrification. Heating supply mix is also different in equilibrium, and centralized formulation as 60 % of heating is supplied by air-source heat pump in the equilibrium formulation while only about 30% of the heating is supplied by air-source heat pump in the centralized formulation. Table 6-4 shows that while the results for total emissions is similar for the equilibrium and centralized formulation, the mix of electricity and heating supply technologies are very different.

In real-world situations, different stakeholders are engaged in an energy system and make decisions based on their advantage. The decisions made by different stakeholders may be in contrast with others and increase the overall cost of the system. Planning for GHG emission reduction using whole-system approaches and central planning, where all systems of the energy system are optimized at the same time will show the most cost-effective pathway for meeting GHG emission reduction goals. The centralized formulation can help identify the energy systems that can contribute to overall GHG emission reduction targets at a lower cost or technologies that can replace fossil fuel-based systems cost-effectively. An outcome of centralized planning models can be identifying the most cost-effective pathway in reducing GHG emissions. In the modeling developed in this study, for instance, centralized planning shows that decarbonizing the electricity system is a favorable pathway compared to decarbonizing heat. This pathway, however, may not happen in real-world cases due to the presence of different stakeholders. The results of the equilibrium formulation show that when the decisions of different stakeholders are considered in the modeling, heat decarbonization may lead to increase in emissions from the electricity system with a carbon price of £300 per tonne CO_2. Centralized modeling is not able to reflect the real world's situation where different stakeholders make decisions based on their objective and not necessarily the whole system's objective. In that sense, equilibrium and multi-level approaches can give a better understanding of the stakeholders' behavior in an energy system and how they interact with each other.

6.5 Conclusion

In this study, an equilibrium formulation for the planning of low-carbon electricity and heat is presented. In the equilibrium formulation, the electricity system problem is at the higher level with the objective of supplying electricity demand with lowest cost. The heat system problem is at the lower level with the objective of supplying heat with the lowest cost. While the levels in the developed formulation are solved separately, the output of each level affects the decisions made at the other level. Electricity prices calculated from the heat problem affect the selection of heating technologies in the heat system while the electricity demand used for heating calculated in the heat system problem affects the type and mix of electricity generation technologies in the electricity system. To show the application of equilibrium modeling in analyzing heat and electricity system decarbonization, a centralized formulation that solves the heat and electricity problem at the same time is also developed, and the results are presented and compared.

Both developed formulations are solved for carbon prices of £18, £30, £70, £100, £150, £200, and £300 per tonne CO_2. The results of our analysis for both equilibrium and centralized formulations shows that for carbon prices of £18, £30, and £70 per tonne CO_2, the dominant electricity generation technology is CCGT, supplying more than 70% of the electricity demand. Natural gas boiler is also the dominant heating technology supplying 80% (the technology limit) of the heating demand. in other words, for carbon prices of £70 per tonne CO_2, negligible decarbonization happens in electricity and heat system and increasing the carbon prices only leads to an increase in levelized cost of electricity and heat. When carbon price increases to £100, and then £150, and £200 per tonne CO_2, decarbonization in the electricity supply happens by nuclear power replacing CCGT share in electricity supply. For carbon prices of £100 per tonne CO_2 and higher, an increase in carbon price leads to a bigger share for nuclear power in electricity generation. The share of renewable energy technologies, however, does not change and their capacity remains at the current level (current capacity of renewable generation capacity has to be maintained in the electricity system as a constraint of the problem). For carbon prices of £100, £150, and £200 per tonne CO_2, natural gas boiler remains the dominant heat electricity supply with 80% share while air-source heat pump starts emerging as a cost-effective technology when carbon price increases to £150 per tonne CO_2.

For carbon prices of £200 per tonne CO_2 and lower, equilibrium formulation and centralized formulation of the problem led to similar results for electricity and heat supply mixes. For a carbon price of £300 per tonne CO_2, however, equilibrium and centralized formulation lead to very different results, though. For the centralized formulation, a carbon price increase from £200 to £300 shows a similar trend for carbon price increase from £70 and upward with an increase in the share of nuclear power in electricity supply. In the centralized formulation for a carbon price of £300 per tonne CO_2, heat supply is 52.7% natural gas boiler, 7.2% fuel cell micro-CHP, 10% community-scale biomass CHP, and 30.1% air-source heat pump. In the equilibrium formulation, heat supply is 30% natural gas boiler, 10% community-scale biomass CHP, and 60% air-source heat pump. As can be seen, heat electrification has happened at a larger scale when the problem is solved using equilibrium formulation. This electrification, however, leads to an increased share of CCGT in electricity supply since nuclear power has reached its capacity limited by technology build rate.

Our modeling shows that solving the problem via equilibrium and centralized formulation may show similar total emission values for heat and electricity supply. However, the mix of technologies in electricity and heat supply in the equilibrium and centralized formulation may be different. More specifically, the centralized formulation has less complexity compared to equilibrium formulation since centralized optimization problems do not have a convergence challenge.

In the centralized formulation, the problem is solved by a single decision-maker, and there is no interaction between stakeholders. As a result, emission from heat supply may be sacrificed to decrease GHG emission from electricity supply as it leads to a lower overall system cost.

This study contributes to the literature by presenting an equilibrium planning model for interdependent heat and electricity systems that takes into account the decisions made by different stakeholders aiming at optimizing their own objectives.

1. Presenting an equilibrium formulation that reflects the rational decision making of stakeholders in the heat and electricity system.
2. Providing an analytical tool for assessing policies such as carbon pricing on the planning of heat and electricity systems.
3. Analyzing the application of equilibrium and centralized formulation for the planning of low-carbon electricity and heat systems.

7 Contributions, and Future Work

7.1 Contributions of this work

This thesis is aimed at developing multilevel models for analyzing the interaction of different stakeholders in energy systems. Different models are developed in this thesis to:

1. Assess the role of renewable energy and energy storage systems in Ontario and how they can be used to reduce GHG emissions in the province considering the objectives of all engaged stakeholders; and

2. Analyze the interaction of heat and electricity supply systems to investigate the effect of heat decarbonization on the development of heat and electricity technologies using two different methodologies.

This thesis contributes to the area of energy system modeling and analysis by:

1. Presenting models for analyzing the effect of government incentives on the development of renewable energy and storage technologies on the objectives of different stakeholders in a microgrid;
2. Analyzing the cost-effectiveness of government policies for the development of different energy conversion and storage technologies for GHG emission reduction in the industrial and residential sectors in Ontario, Canada;
3. Investigating th cost-efficiency of using battery-powered and fuel cell-powered forklifts in reducing GHG emissions in Ontario, Canada considering the objectives of different stakeholders; and
4. Investigating the interaction of the heat and electricity sectors at a national scale using bilevel and centralized modeling approaches.

The contribution of this thesis is presented through four studies. In the first and the second studies, deterministic models are developed to analyze the interaction of the government, the energy investor (energy hub operator), and the energy consumer in the context of a microgrid.

In the first study, a deterministic model is developed to compare the cost-efficiency of renewable energy generation and hydrogen energy storage technologies on the advantages of the government, the energy hub operator and energy consumer in Ontario. Different scenarios including hydrogen production using Ontario's electricity with and without underground storage option, hydrogen production using wind power with and without underground storage option, and hydrogen production with a mix of wind power and grid electricity are considered. In the first study, it is assumed that the produced hydrogen is blended with natural gas to form HENG and is used in an industrial facility in internal combustion engines and a drying furnace. In the first study, it is assumed that the government has the option of incentivizing each of these projects and objectives of all stakeholders are calculated in each of the mentioned scenarios. The objective of the government is spending the minimum amount of incentives for decreasing one kg of CO_2 emission. The objective of the energy consumer is minimizing energy cost, and the objective of the energy hub operator is maximizing their NPV from investing in energy infrastructure. The results of the model in the first study show that with the same incentive policy, incentivizing hydrogen production with grid electricity is the most cost-efficient option for the government as it leads to the highest GHG emission reduction with the same amount of incentives paid. In other words, taking advantage of Ontario's clean surplus power leads to lower GHG emission reduction costs compared to the development of new wind power capacity. The results of the first study also show that incentivizing wind power development is more profitable for the energy hub operator as it leads to a higher NPV for them.

In the second study, the monetized health impacts from fossil fuel consumption and taxes collected from the energy hub operator and the energy consumer are added to the model and the effect of battery energy storage on the advantages of stakeholders is also analyzed with a deterministic model. Additionally, the effect of the development of wind and solar power plants on energy consumer's electricity cost is considered in the second study. Two streams of energy incentives were compared in the second study: incentives for renewable energy generation technologies and incentives for energy storage technologies. The first type aims to increase the share of renewable energies in the electricity system while the second type aims the development of systems which use clean electricity to replace fossil fuels in other sectors of an energy system such as the transportation, residential and industrial sector. The comparison was based on the advantages of the government and the energy consumer in Ontario. The results of the second study show that when the electricity grid is highly dependent on fossil fuels, replacing fossil fuel-based electricity generation with renewable power is a more cost-effective pathways in reducing GHG emissions compared to the development of energy storage systems. However, the development of battery and hydrogen energy storage systems is more cost-effective in reducing GHG emissions considering Ontario's current electricity mix. The analysis in the second study also shows that battery storage and hydrogen storage are complementary technologies for reducing GHG emissions in Ontario.

The first two studies were focused on comparing the cost-efficiency of renewable energy generation and energy storage technologies on the advantages of all engaged stakeholders in the context of a microgrid. The results of the first two studies show that the development of energy storage systems and using surplus clean power for reducing GHG emissions in the industrial and commercial sectors is a more cost-effective pathway for reducing GHG emissions in Ontario compared to the development of more wind and solar power generation capacity considering Ontario's current electricity mix.

In the third study, an optimization model is developed to find the optimum mix for hydrogen and battery energy storage technologies considering Ontario's electricity mix. The optimization model developed in the third study is based on game theory with two players (stakeholders): the government and the energy consumer, which is an industrial facility that operates diesel forklifts. The energy consumer's objective is minimizing the cost of operating forklifts, which includes capital cost, operation, and maintenance cost, labor cost, and fuel cost. The energy consumer has the option of operating diesel, battery-powered, and fuel cell-powered forklifts and will choose the forklift mix that has the lowest cost for them. The government's objective is reducing GHG emissions from the energy consumer's forklift use with the lowest level of incentives paid. The results of the third study show that the support from the government for replacement of diesel forklifts with battery-powered and fuel cell-powered forklifts is advantageous for both stakeholders. The model developed in the third study also helps in determining the optimum mix of battery and hydrogen technologies for maximizing the advantages of the government and the industrial facility when different social costs of carbon are considered.

A similar analysis is done to analyze the potential of clean surplus power in Ontario in reducing GHG emissions in the residential sector in Ontario in the presence of government incentives.

In the fourth study, an iterative optimization model is developed to analyze the interaction of the heat and electricity sectors at a national level in the Great Britain. Independent mathematical models for optimizing the selection of technologies in heat and electricity supply systems are developed. Two developed models are solved iteratively to find the optimum selection of technologies in the heat and electricity supply systems when their interaction is considered. Additionally, a centralized model is developed, which optimizes heat and electricity supply technologies simultaneously. The results of both methods are compared to show the advantages of iterative approach in the modeling of energy systems.

The models developed in the first three studies of this thesis can help policymakers gain insight into how the development of energy storage and renewable energy technologies can affect the objectives of all stakeholders in a microgrid when GHG emission reduction policies are pursued by the government. The models developed in the fourth study enable us to understand the interaction of heat and electricity supply systems and how changes in one can affect the other.

7.2 Recommendations for future work

Although the models developed in this thesis provide insight on the interaction of different stakeholders and energy sectors, there is still opportunity to further investigate energy systems using multilevel and multi-stakeholder modeling. Based on the studies done in this thesis, the following directions may be recommended for future study in the multi-stakeholder analysis of energy systems:

1. Including uncertainty in modeling: Hourly data for electricity price, wind and solar power potential, and electricity and heat demands were considered in this thesis to reflect the variation in these factors. However, including uncertainty will make the models more suitable for real-world applications. While using the available hourly data helps us understand the potential of different technologies and how they operate in interaction with each other, stochastic modeling is of great importance when a detailed design is required.
2. Considering more energy conversion and storage technologies in the modeling: The models developed in this thesis have contributed to the literature by considering the objectives of multiple stakeholders in an energy system and thus, presenting a more comprehensive overview of the energy system. However, not all available technologies were considered in the studies. Battery and hydrogen energy storage were the storage technologies considered in the first three studies while the potential of other types of storage such as compressed air energy storage and flywheels may be investigated in future work. Similarly, more technologies can be added to the models

developed for heat and electricity supply systems to present a more comprehensive analysis of those sectors.

3. Including all the energy sectors in analyzing the interaction of different sectors in an energy system: The interaction of heat and electricity has been investigated in this thesis. However, the effect of changes and transitions in other energy sectors such as transportation on heat and electricity supply systems has not been investigated in this thesis. In that sense, developing models that present a more comprehensive view of a national energy system while all the energy sectors including electricity, building, commercial, industrial, and transportation are considered can be of great potential for providing a planning tool for policymakers.

4. More detailed modeling of the technologies and energy sectors: A more detailed modeling of technologies and energy sectors would increase the accuracy of the results. For the technologies, using more accurate efficiency curves and considering the economy of scale in calculating the costs will help in having more accurate comparisons. Considering additional parameters such as more detailed modeling of electricity transmission system planning also provides more accurate results in energy planning analysis.

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9 Appendix A: List of Parameters, Variables, Subscripts and Indices

9.1 Appendix A.3.1: List of Parameters and Variables for Chapter 3

FC_i	Fuel cost in case i
CC_i	Carbon cost in case i
Hc	Hydrogen consumption in *kg per hour*
Hp	Hydrogen price in *CAD per kg*
NGc	Natural gas consumption in *MMBtu per hour*
NGp	Natural gas price calculated based on 2015 average Henry Hub natural gas spot price in *US Dollar per one Million Btu*
GEP	Grid Electricity Price
LSP	Low Set Price
HSP	High Set Price
P_{DE}	Power needed for electrolyzer to meet hydrogen demand
P_{ST}	Power needed for electrolyzer to fill the storage tank
P_{EL}	Power fed to the electrolyzer
P_{needed}	Power bought from the grid
η_E	Electrolyzer efficiency
$H_{produced}$	Hydrogen produced by electrolyzer
H_{rated}	Maximum hydrogen production of electrolyzer
H_{demand}	Hydrogen demand
H_{extra}	Hydrogen sent to the storage tank
H_{needed}	Hydrogen from the storage tank
P_{WF}	Power generated by wind farm
P_{ME}	Minimum power of electrolyzer
P_{DE}	Power needed for electrolyzer to meet hydrogen demand

P_{extra}	Power sold to the grid

9.2 Appendix A.4.1: List of Parameters and Variables for Chapter 4

r	Discount rate
t	Year
T	Project lifetime

9.3 Appendix A.5.1: List of Parameters and Variables for Chapter 5

f	The government's objective function
f_{best}	The optimum value for the leader's objective function
z	The energy consumer's objective function
x	The government's incentive level
y_1	The consumer's decision variables and show the number of battery-powered forklifts
y_2	The consumer's decision variables and show the number of fuel cell-powered forklifts
y_3	The consumer's decision variables and show the number of diesel forklifts
TDC	The amount of charges paid by the government to cover transmission and distribution charges of discounted power in *CAD per kWh*
α	The social cost of carbon in *CAD per tonne of* CO_2
e	The emission reduction in *tonne of* CO_2
ACL	Amortized cost of lift in *$ per forklift per year*
CFI	Cost of fuel infrastructure in *$ per forklift per year*
CRI	Cost of recharge infrastructure in *$ per forklift per year*

LC	Labor cost in *\$ per forklift per year*
$CIWS$	Cost of infrastructure warehouse space in *\$ per forklift per year*
$FLMC$	Forklift maintenance cost in *\$ per forklift per year*
BMC	Battery maintenance cost in *\$ per forklift per year*
$FCMC$	Fuel cell maintenance cost in *\$ per forklift per year*
EC	The sum of electricity purchase cost at both discounted and not discounted hours in *\$ per year*
HC	The cost of electricity purchased for producing hydrogen, annualized electrolyzer cost, annualized hydrogen storage tank cost, and annualized compressor cost in *\$ per year*
i	Iteration number in the game theory model

9.4 Appendix A.6.1: List of Parameters and Variables for Chapter 6

$HTCC_i$	The annualized capital cost of heating technology i in £ *per unit -15 MWh_{th}- of heat supply*
$HTO\&MC_i$	Operation and maintenance cost of the heating technology i in £ *per unit-15 MWh_{th}*- of heat supply per year
$Heat\_demand(t)$	Heat demand at hour t in kWh_{th}
$HT\_Share\_Limit_i$	The upper limit of heating technology i in heating supply mix *(% of heat supply*)
$EmFactor_k$	The emission factor of fuel input k in *gram of CO_2 per kWh*
$Carbon\_Price$	Carbon price in £ *per tonne CO_{2eq}*
FP_k	Price of fuel k in £/*kWh*
$\eta_{heating,i}$	Heating efficiency or COP of heating technology i (%)
TCC_j	The annualized capital cost of electricity generation technology j in £/kW_e-*yr*

$FO\&MC_j$	Fixed operation and maintenance cost of electricity generation technology j in £ *per* kW_e *of technology capacity per year*
$VO\&MC_j$	Variable operation and maintenance cost of electricity generation technology j in £ *per* kWh_e *of electricity generated*
$Electricity\_Demand(t)$	Electricity demand at hour t in kWh_e
$\eta_{electrical,j}$	Electrical efficiency of electricity technology j in *%*
$Build\_rate_j$	Build rate for electricity technology j in kW_e *per year*
$Min\_Renewable\_Cap_j$	Minimum capacity for renewable electricity technology j in kW_e
$Pumped\_Hydro\_StoreCap$	Storage capacity of pumped hydro storage system in kWh_e
$HSPOF$	Heat supply problem objective function in £
HT_Share_i	Share of heating technology i in supplying heating demand in *%*
$EIC_{k,i}(t)$	Cost of fuel k (electricity, biomass, biogas and natural gas) in technology i at hour t in £ *per kWh of fuel*
$Input_{k,i}(t)$	Fuel k consumption in heating technology i at hour t in *kWh*
$Heat\_Output_i(t)$	Heating output of heating technology i at hour t in kWh_{th}
$ESPOF$	Electricity supply problem's objective function value in £
TC_j	The capacity of electricity generation technology j in kW_e
$EIC_{k,j}$	cost of fuel k consumption in electricity generation technology j at hour t in £ *per kWh of input fuel*
$Electricity\_Output_j(t)$	The electricity output of electricity generation technology j at hour t in kWh_e
$Electricity\_Input_{Pumped\_Hydro}(t)$	Electricity input to pumped hydro technology at hour t in kWh_e
$Electricity\_Output_{Pumped\_Hydro}(t)$	The electricity output of pumped hydro technology at hour t in kWh_e

$Storage\_level_{Pumped\_Hydro}(t)$	Pumped hydro storage level in kWh_e
$Capacity_j$	The capacity of electricity generation technology j in kW_e
$Input_{k,j}(t)$	Fuel k consumption in electricity generation technology j at hour t in *kWh of fuel*
$EDFH_h(t)$	Electricity demand for heating at hour t and iteration h in £ *per* MWh_e
$EP_h(t)$	Electricity price at hour t and step h in in £ *per* MWh_e
$TED_h(t)$	Total electricity demand (electricity demand plus electricity demand for heating) at hour t and step h in MWh_e